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Transcript Exhibit(s)

E-01551A-04-0876

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To: Docket Control

Re: Southwest Gas Corporation / Rates
Volumes I through VI (CONCLUDED)
October 3 through 11, 2005

STATUS OF ORIGINAL EXHIBITS

FILED WITH DOCKET CONTROL
10-12-2005

STAFF

1 through 23, 26, and 27

SOUTHWEST GAS

1 through 49, and 51

RUCO

1 through 12

ARIZONA COMMUNITY ACTION AGENCY (ACAA)

1

<u>AUIA</u>

1 and 2

<u>SWEEP</u>

1 and 2

<u>DEPARTMENT OF DEFENSE (DOD)</u>

1

EXHIBIT NUMBERS NOT UTILIZED ***Numbers skipped or exhibit not used***

<u>STAFF</u>

24 and 25

ORIGINAL EXHIBITS RETURNED TO PARTIES

<u>SOUTHWEST GAS</u>

50 Pending

Copy to:

Dwight D. Nodes, ACALJ (letter only)
Staff, Jason Gellman, Esq.
Southwest Gas Corp., Andy Bettwy, Esq.
RUCO, Scott Wakefield, Esq.

Southwest Gas Corporation
Docket No. G-01551A-04-0876

EXHIBIT
A-40
Admitted

Table of Contents
of
Prepared Rejoinder Testimony
of
THEODORE K. WOOD

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
THEODORE K. WOOD

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Theodore K. Wood. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

Q. 2 Did you sponsor direct and rebuttal testimony on behalf of Southwest in this proceeding?

A. 2 Yes.

Q. 3 What is the purpose of your rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to respond to specific aspects of the surrebuttal testimony presented by Stephen G. Hill, witness for the Arizona Corporation Commission Utilities Division Staff (Staff) regarding his recommendations and comments concerning capital structure. My rebuttal and rejoinder testimonies may not specifically respond to each issue or argument brought forth by the respective intervening parties in their direct and surrebuttal testimony. My silence should not be taken as acceptance of any intervening party's position, but rather that my previously filed direct and rebuttal testimonies adequately support the Company's position.

Q. 4 Did you prepare any exhibits to support your rejoinder testimony?

A. 4 Yes. I prepared the exhibits identified as Rejoinder Exhibit No.__(TKW-1) and Rejoinder Exhibit No.__(TKW-4).

Q. 5 Please summarize the specific issues your rejoinder testimony will address.

A. 5 My rejoinder testimony will address certain comments made by Mr. Hill in his surrebuttal testimony concerning the appropriate ratemaking capital structure that should be used in this proceeding.

<u>STAFF'S RECOMMENDED CAPITAL STRUCTURE</u>

Q. 6 Before responding to specific comments and details of Mr. Hill's testimony, do you have any general comments regarding his testimony?

A. 6 Yes. A common theme contained in Mr. Hill's direct and continuing in his surrebuttal testimony, is his mischaracterization of the use of a hypothetical capital structure by: (1) classifying it as a subsidy to the Company; (2) claiming it provides the Company a means to earn in excess of the allowed return set by the Commission; and (3) claiming it provides for returns on equity that the Company does not have. The simple fact of the matter is that the Company's cost of common equity is higher than the average of the proxy groups used in this proceeding, which is required to compensate for the Company's relatively higher investment risk. The use of the hypothetical capital structure adjusts for the difference in leverage and, in doing so, protects the Company's ability to provide necessary service, attract capital on a reasonable basis, and maintain its financial integrity, all of which have benefits to the Company's customers. Mr. Hill's characterization of the hypothetical capital structure as providing anything more than the Company's required risk-adjusted rate of return is misleading.

Q. 7 What is your response to Mr. Hill's criticism on page 3 of his surrebuttal testimony, wherein he states that you have failed to mention the regulatory precedent by the Commission for establishing the hypothetical capital structure?

A. 7 In both my direct and rebuttal testimony, I have cited the regulatory precedent for employing a hypothetical capital structure, including the Company's currently authorized capital structure by this Commission (Theodore Wood Direct Testimony, page 23). It is further important to point out that the Commission has previously authorized a hypothetical capital structure which contains a higher equity component for the Company than the 42 percent the Company and RUCO are recommending or the 40 percent that Staff has recommended. In Decision No. 57075, the Commission allowed for a hypothetical capital structure with 45 percent common equity component.

Q. 8 What is your response to Mr. Hill's comments on pages 3 and 4 of his surrebuttal testimony concerning the Company's efforts to improve its capital structure?

A. 8 Mr. Hill testifies that the facts regarding the issuance of additional common stock, in isolation, do not support the Company's requested 42 percent common equity ratio. I believe as does Mr. Hill (Stephen Hill Surrebuttal Testimony, page 3) that the Company's common stock issuances should not be viewed in isolation, because to understand the Company's current capital structure you need to analyze the circumstances of the Company, including, without limitation, the Company's operating and regulatory environment, the resulting achieved financial performance, and the Company's efforts to manage its capital structure.

In my rebuttal testimony, I provided some key financial statistics for the time period 1994-2004. During this time period, the Company experienced an annual customer growth rate of 5.6 percent (adding 680,739 customers) and had capital expenditure requirements of approximately $2.3 billion. The Company's ability to finance growth and improve its capital structure has been negatively impacted by the Company's substandard returns, in which the Company has realized an average return on common equity of 6 percent.

Concerning the Company's financial performance, Mr. Hill states he believes:

> "a regulated utility should have an opportunity, under efficient and effective management, to earn the return it is allowed. If there are technical impediments to that end that can be addressed in regulatory format, then they should be addressed" (Stephen Hill Surrebuttal Testimony, page 8).

The Company has been proactive in the regulatory arena to address issues that have impacted the Company's financial performance. During the time period 1994-2005, the Company has filed 15 general rate cases in its natural gas jurisdictions. In this current proceeding, the Company has presented rate design proposals to address the issue of declining average customer usage which has negatively impacted the Company's ability to earn its authorized rate of return. While the Company has filed general rate cases to address the issues affecting its financial performance, the Company has also been detrimentally impacted in the process by regulatory lag. Nowhere in Mr. Hill's testimony does he address the key factors that have impaired the Company's ability to improve its capital structure beyond a 37 percent equity ratio, despite its good faith efforts. The Company's circumstances are germane to setting the hypothetical capital structure in this proceeding, and should be strongly considered by the Commission.

Q. 9 What is your response to Mr. Hill's comments on pages 3 and 4 of his surrebuttal testimony, wherein Mr. Hill states that the Company's efforts to add additional common equity would only be important if and only if the amount of common equity ratio had increased?

A. 9 First, regardless of whether the common equity ratio has increased, Southwest's efforts are still important because it demonstrates the Company's commitment and efforts to improve its capital structure.

Second, Mr. Hill is incorrect when he suggests the Company's common equity ratio has not increased since 1995. Mr. Hill states that the Company had a common equity ratio of 36.9 percent in 1995 and has about the same common equity ratio currently of 36.7 percent. This comparison is misleading, as the common equity ratios he compares are not a proper comparison. For the 1995 common equity ratio, Mr. Hill references his Exhibit__(SGH-1), Schedule 2, Page 3 of 6, which he constructed from data obtained from the MSN MoneyCentral website. The website provides the Company's debt-to-equity ratio, but does not provide the common equity ratio, so I assume that Mr. Hill solved for the corresponding equity ratio based on the reported debt-to-equity ratio[1]. Mr. Hill compares this

[1] Percent Equity = 1 / (Debt-to-Equity Ratio+1)

to Southwest's reported Company consolidated common equity ratio as of June 30, 2005.

In order to make an accurate assessment of the Company's equity ratio improvement, one can not use two different bases for computing equity ratios and then make a comparison. In order to accurately assess the Company's improvement, I have provided the Company's common equity ratios for the time period 1995 through June 2005 in Rejoinder Exhibit No.__(TKW-1). The Company had a common equity ratio in 1995 of 31.1 percent, which has improved to 37.0 percent as of June 30, 2005. Based on this data, clearly the Company has improved its common equity ratio since 1995, despite the financial challenges from the combination of rapid customer growth and the Company's inability to earn its authorized rate of return.

Q. 10 What is your response to Mr. Hill's comments on pages 4 and 5 of his surrebuttal testimony, wherein he responds to your criticism about his representation of the average common equity ratio in the natural gas industry as reported by AUS Utility Reports?

A. 10 Mr. Hill testifies that in establishing the appropriate common equity ratio for the hypothetical capital structure it is proper to review the average common equity ratio derived from 30 companies reported by AUS Utility Reports[2], which includes gas

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[2] Hill Direct Testimony, Schedule_(SGH-1), Schedule 2, Page 4 of 6.

distribution and integrated natural gas companies. Mr. Hill's justification of this position is found on pages 3 and 4 of his surrebuttal testimony where he states:

> "Those diversified operations are riskier operations than that of a gas distribution utility like Southwest Gas. Firms that carry higher operating risk are optimally capitalized with more equity and less debt than less risky firms. Therefore, relying on the average common equity ratio for both distributors and diversified gas companies (41.7 percent, see Hill Direct, page 23) provides a conservative estimate of an appropriate equity ratio for the less-risky distribution operation."

The fundamental problem with Mr. Hill's justification is that it is not supported by his own data. The average of the 30 companies, which includes the higher risk diversified companies, has a common equity ratio of 41.7 percent which is lower than the 42.7 percent average common equity ratio for the 11 natural gas distribution companies of Mr. Hill's proxy group, which are also included in the 30 company sample. According to Mr. Hill, the natural gas distribution companies are less risky than the diversified companies and, therefore, they should have lower common equity ratios; yet they do not.

The reason why the data does not conform to Mr. Hill's justification is because, as I pointed out in my rebuttal testimony on pages 4 and 5, the sample includes companies that are in financial distress, such as the El Paso Corporation with a 16 percent common equity ratio. The inclusion of companies in financial distress has biased the average common equity ratio to be lower. This fact is supported as the average common equity ratio reported by Mr. Hill of the investment grade companies in the 30-company sample is 43.9 percent[3]. As a result, it is inappropriate to use the average common equity ratio of this 30-company sample to determine the appropriate common equity ratio in this proceeding.

Q. 11 What is your response to Mr. Hill's comments on pages 4 and 5 of his surrebuttal testimony, wherein he responds to your criticism about his representation of the average common equity ratio using total rather than permanent capital structures?

A. 11 The difference between permanent and total capital structures is that a total capital structure includes short-term debt. My concerns with using common equity ratios based on total capital structures are due to the following: (1) the Commission practice to use permanent capital structure for ratemaking; and (2) that it is inappropriate to include short-term debt for rate making capital structures. Utilities generally use short-term debt to finance working capital requirements, including deferred energy

[3] Hill Direct Testimony, Schedule_(SGH-1), Schedule 2, Page 4 of 6.

balances, and to finance construction work in process. Short-term debt that is used to finance a utility's working capital requirements and deferred energy receivable balances should not be included in setting an allowed rate of return, as this would lead to underestimating the true cost of financing a utility's long-term rate base assets. For example, if a utility was required to finance deferred energy receivable balances, a utility should not be detrimentally impacted by setting a lower allowed rate of return on its long-term rate base assets by including lower cost short-term debt that is used to finance short-term deferred energy balances.

Mr. Hill's criticism is that the assessment of financial risk should be based on total debt, which also includes short-term debt. To accurately make comparisons of capital structures based on total capital structure, which includes short-term debt, then annual average capital structures should be utilized rather than a single point in time during the year. This is due to the seasonal nature of the natural gas distribution business, where operating cash flows and income are higher during the heating season and lower the remainder of the year. Correspondingly, short-term debt balances generally are reduced during the heating season and then build-up outside of the heating season to accommodate the working capital requirements. I have calculated the annual average common equity ratios for Mr. Hill's proxy group for the period 2000-2004, which are displayed in Rejoinder Exhibit No.__(TKW-2) and are based on the reported quarterly capital structures. Utilizing the average total capital structure, the average common equity ratio for Mr. Hill's proxy group is 46.8 percent for 2004 and 44.5 percent for 2003. In comparison to the common equity ratios of Mr. Hill's proxy group based on year end numbers (see Rebuttal Exhibit No.__(TKW-2)), the average common equity ratios reflect higher ratios, after normalizing for the seasonality of the natural gas distribution business.

The Company's requested 42 percent common equity ratio is reasonable when compared to both the average common equity ratios of Mr. Hill's own proxy group and Mr. Hill's standard of reasonableness (Stephen Hill Direct, pages 23 and 24). In addition, the 42 percent equity ratio is consistent with the past Commission practice to set the equity ratio for the hypothetical capital structure above the Company's actual ratio, but below the average of similar-risk natural gas distribution utilities. Provided in Rejoinder Exhibit No.__(TKW-3) is a summary of the average common equity ratios of the proxy groups used by Staff, RUCO, and the Company to estimate the cost of common equity in this proceeding.

Q. 12 Is Mr. Hill correct on pages 4 and 5 of his surrebuttal testimony, wherein he claims that the Company's ratemaking capital structure in this proceeding effectively contains short-term debt?

A. 12 No. Mr. Hill fails to recognize the difference between variable rate long-term debt and short-term debt. As part of the Company's long-term debt, the Company has consistently used revolving bank credit facilities to borrow long-term in the form of London Inter-Bank Offered Rate (LIBOR) based loans or commercial paper, which is used to finance long-term assets of the Company. Even though the interest rate paid on this debt is tied to a short-term rate does not classify it as short-term debt. Under Generally Accepted Accounting Principals, borrowings under a revolving credit agreement may be classified as long-term debt if the credit agreement extends for at least one year beyond the date of the financial statements. The distinction between long-term and short-term debt under a multi-year credit agreement is based on the life of the asset it is used to finance.

The Company currently has a $300 million bank credit facility that expires in April 2010 (5-year maturity). The Company's designation of $150 million of the facility as long-term debt and $150 million as short-term debt is based on the use of the funds. The long-term portion is expected to be outstanding at all times as part of the Company's permanent capital, as it used to finance long-term utility assets, while the short-term portion of the facility is used to finance the Company's working capital requirements, with the outstanding balance fluctuating during the year based on the Company's seasonal working capital needs, including the need to finance purchased gas adjustment balances.

Q. 13 What is your response to Mr. Hill's surrebuttal testimony on pages 6 and 7, where he responds to your criticism of his calculation of the annual impact of the Company's requested capital structure?

A. 13 Mr. Hill correctly states that the required return for the Company's common equity as determined by investors in the market, is based on the Company's actual capital structure. Given that the Company's actual capital structure has more leverage, lower credit ratings, and higher financial risk relative to the proxy group used to estimate the cost of common equity, the Company's investors will require a higher rate of return. Mr. Hill testifies that since Company witness Frank Hanley adjusted his cost of equity recommendation upward for the Company's greater financial risk, it was appropriate to use the same cost of equity in the Company's actual and requested capital structures to compute the annual impact of using the hypothetical capital structure. Mr. Hill is incorrect in his presumption, as the adjustment made by Mr. Hanley was for the difference between the Company's Baa2 bond rating and the proxy group's average bond rating of A2 (Frank Hanley's Direct Testimony, page 53, lines 7 through 14). Given the Company's Standard and Poor's (S&P) business profile of "3" and S&P's Utility Group financial target debt-to-capital ratio, the use of a hypothetical capital structure with a 42 percent common equity ratio is still consistent with a "BBB" credit rating. The adjustment is still appropriate for the difference in the bond ratings of the Company's hypothetical capital structure and the bond ratings of the proxy groups used by Mr. Hanley. Further, as I pointed out in my rebuttal testimony on page 10, Mr. Hanley specifically stated if the Company's actual capital structure were used, his recommended cost of common equity would be higher due to the additional financial risk.

In my rebuttal testimony, pages 9 through 11, I pointed out the critical flaw in Mr. Hill's original calculation was his omission of adjusting the return on equity upward when going from a capital structure with a 42 percent common equity ratio to a capital structure with a 35 percent common equity ratio. In response, Mr. Hill in his surrebuttal testimony, re-estimates the annual impact by adjusting the return on common equity upward by 25 basis points to account for the differences of 700 basis points in the common equity ratio between the Company's actual and hypothetical capital structures. His justification for the adjustment of 25 basis points is based on the 50 basis point range of cost of equity estimates for the highest and lowest risk companies in his proxy group. The key assumption made by Mr. Hill is that his ad hoc 25 basis point adjustment to the return on equity is the correct adjustment to compensate for the differences in capital structures. Mr. Hill provides no other supporting evidence for his adjustment.

Mr. Hanley pointed out in his rebuttal testimony, that Mr. Hill has placed primary reliance on the DCF model for his cost of equity analysis. One of the problems with using the DCF method is that it does not explicitly consider the risk of the investment. As a result, you cannot base adjustments for leverage based on ranges of estimates that were derived from a DCF model. In fact, there is no DCF methodology to adjust for differences in financial risk. This issue was addressed by Bradford Cornell, who stated:

> "From the standpoint of the cost of equity, comparability depends not only on the line of business, but also on financial leverage. Two otherwise identical companies will not have the same cost of equity if they have markedly different capital structures. Whereas

adjustments for leverage can be made using asset-pricing models, in the context of the DCF approach there is no procedure for taking account of differences in financial leverage."[4]

As a result, Mr. Hill's second attempt to estimate the annual impact of the hypothetical capital structure is still suspect and should not be relied on by the Commission.

Q. 14 Please comment on Mr. Hill's assertion on pages 9 and 10 of his surrebuttal testimony that the Company does not have "every incentive" to improve its capital structure.

A. 14 Mr. Hill's assertion that this Company has a ratemaking "scheme" in which the Company has purposely capitalized itself to retain a bottom of the investment grade credit rating in order to take advantage of employing a ratemaking hypothetical capital structure is simply ludicrous. The Company has every incentive to improve its capital structure and improve its bond ratings, and has recently demonstrated this by the additional common stock issued through its $60 million Equity Shelf Program. The majority of the common stock issued through the Equity Shelf Program occurred after the end of the test period and the Company has improved its common equity ratio to 37 percent as of June 30, 2005. Given the fact the Company will continue to experience rapid

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[4] Bradford Cornell, John I. Hirshleifer, and Elizabeth P. James, "Estimating the Cost of Equity Capital", Contemporary Finance Digest, Autumn 1997, 5-26.

customer growth, be required to fund significant levels of capital expenditures, and is now facing significantly higher natural gas prices going into the 2005-2006 heating season, in addition to rising interest rates, the Company needs regulatory support to augment its efforts to improve its capital structure and its bottom of the investment grade bond rating. The ability for the Company to improve its bond rating was addressed by Standard & Poor's (S&P) in their most recent summary report for the Company (see Rejoinder Exhibit No.__(TKW-4)), where S&P stated:

> "Ratings improvement hinges on achieving better rates of return and rate design improvements in Arizona, as well as maintaining improved regulatory treatment in Nevada."

Over the past decade, the Company has been one of the fastest growing gas distribution utilities in the nation requiring significant infrastructure investment, while at the same time realizing one of the lowest average rates of return on common equity in the natural gas distribution industry. The combination of rapid growth and low realized rates of return has severely impeded the Company's ability to improve its capital structure. As pointed out in my rebuttal testimony, pages 18 and 19, if the Company had earned an industry average return over the time period 1994-

2004, then the Company's common equity ratio would be approximately 47 percent, which is close to the industry average common equity ratio. The Company's target capital structure is management's choice. However, the Company's inability to achieve its target capital structure, despite the tangible efforts made by the Company as demonstrated by the large amounts of common stock issuances, is much more a function of the Company's rapid growth rate environment and below-authorized rates of return. In order to achieve and sustain the goal of an improved capital structure, the Company needs an improved opportunity to achieve its authorized rate of return.

Q. 15 Does this conclude your prepared rejoinder testimony?

A. 15 Yes, it does.

SOUTHWEST GAS CORPORATION
COMMON EQUITY RATIO
FOR THE YEAR ENDED DECEMBER 31

Year	Percent Common Equity
1995	31.10%
1996	34.80%
1997	31.70%
1998	35.60%
1999	35.80%
2000	36.20%
2001	33.00%
2002	34.30%
2003	34.10%
2004	35.31%
June 30, 2005	37.00%

Data from the Company's Monthly Operating Report.

Rejoinder Testimony
Exhibit No.______(TKW-2)

SOUTHWEST GAS CORPORATION
ACC STAFF WITNESS MR. STEPHEN G. HILL'S
PROXY GROUP OF 11 NATURAL GAS DISTRIBUTION COMPANIES

COMMON EQUITY RATIOS BASED ON AVERAGE PERMANENT CAPITAL STRUCTURE[1]

Company	2004	2003	2002	2001	2000	5-Year Average
AGL Resources Inc.	47.80%	47.66%	41.81%	42.30%	48.55%	45.62%
Atmos Energy Corp	52.76%	47.19%	47.29%	53.67%	51.91%	50.56%
Cascade Natural Gas Corp.	47.50%	42.59%	43.00%	50.41%	49.43%	46.59%
Laclede Group, Inc.	50.84%	49.82%	51.84%	53.41%	57.60%	52.70%
New Jersey Resources Corp.	61.50%	59.32%	47.54%	51.63%	52.63%	54.52%
Northwest Natural Gas Co.	52.91%	51.25%	51.15%	51.79%	51.31%	51.68%
Peoples Energy Corp.	50.67%	56.43%	56.85%	56.16%	67.12%	57.45%
Piedmont Natural Gas Co.	57.07%	58.33%	55.56%	55.45%	56.16%	56.51%
South Jersey Industries Inc.	51.54%	47.50%	44.94%	45.45%	46.86%	47.26%
Southwest Gas Corporation	35.22%	34.33%	35.71%	37.62%	35.90%	35.76%
WGL Holdings Inc.	57.80%	56.03%	54.61%	55.97%	56.55%	56.19%
Average	51.42%	50.04%	48.21%	50.35%	52.18%	50.44%
Standard Deviation	6.86%	7.45%	6.54%	6.05%	7.76%	6.37%
Company 's Hypothetical	42.00%	42.00%	42.00%	42.00%	42.00%	42.00%
Difference from Average	9.42%	8.04%	6.21%	8.35%	10.18%	8.44%
Difference in Standard Deviations	1.37	1.08	0.95	1.38	1.31	1.32

COMMON EQUITY RATIOS BASED ON AVERAGE TOTAL CAPITAL STRUCTURE[1]

Company	2004	2003	2002	2001	2000	5-Year Average
AGL Resources Inc.	44.37%	42.31%	34.32%	32.34%	44.16%	39.50%
Atmos Energy Corp	51.32%	44.56%	43.02%	47.47%	40.75%	45.42%
Cascade Natural Gas Corp.	41.81%	41.58%	42.66%	44.69%	48.86%	43.92%
Laclede Group, Inc.	41.80%	38.95%	41.34%	42.05%	46.81%	42.19%
New Jersey Resources Corp.	49.40%	50.23%	44.26%	48.06%	48.37%	48.06%
Northwest Natural Gas Co.	50.06%	48.18%	48.35%	47.36%	48.26%	48.44%
Peoples Energy Corp.	48.01%	47.48%	45.98%	39.93%	47.15%	45.71%
Piedmont Natural Gas Co.	54.78%	51.15%	53.38%	52.08%	50.64%	52.41%
South Jersey Industries Inc.	46.86%	39.52%	35.72%	34.91%	37.17%	38.84%
Southwest Gas Corporation	33.96%	33.95%	33.89%	31.84%	34.16%	33.56%
WGL Holdings Inc.	52.42%	51.07%	50.11%	49.48%	51.56%	50.93%
Average	46.80%	44.45%	43.00%	42.75%	45.26%	44.45%
Standard Deviation	5.96%	5.68%	6.42%	7.11%	5.63%	5.63%
Company 's Hypothetical	42.00%	42.00%	42.00%	42.00%	42.00%	42.00%
Difference from Average	4.80%	2.45%	1.00%	0.75%	3.26%	2.45%
Difference in Standard Deviations	0.81	0.43	0.16	0.11	0.58	0.44

[1] Source - Bloomberg

SOUTHWEST GAS CORPORATION
SUMMARY OF COMMON EQUITY RATIOS

COMMON EQUITY RATIOS BASED ON AVERAGE CAPITAL STRUCTURES[1]

	2004	2003	2002	2001	2000	5-Year Average
ACC Staff (Hill) Proxy Group						
Permanent Capital Structure	51.42%	50.04%	48.21%	50.35%	52.18%	50.44%
Total Capital Structure	46.80%	44.45%	43.00%	42.75%	45.26%	44.45%
RUCO (Rigsby) Proxy Group						
Permanent Capital Structure	51.94%	51.31%	49.90%	51.03%	54.97%	51.83%
Total Capital Structure	46.98%	44.34%	43.57%	42.54%	47.39%	44.97%
Southwest (Hanley) Proxy Groups						
Proxy Group 1 - 5 Companies						
Permanent Capital Structure	53.06%	52.78%	51.06%	52.38%	54.12%	52.68%
Total Capital Structure	47.97%	45.89%	46.02%	45.14%	48.55%	46.71%
Proxy Group 2 - 11 Companies						
Permanent Capital Structure	52.49%	51.52%	49.70%	50.35%	53.90%	51.59%
Total Capital Structure	47.64%	45.19%	43.94%	42.63%	47.82%	45.44%

Recommended Common Equity Ratio	
ACC Staff	40.00%
RUCO	42.00%
Southwest	42.00%
Average Authorized[2]	47.50%

[1] Source: Bloomberg
[2] Average authorized common equity ratio for natural gas distribution companies litigated rate cases for the Year 2003 through June 2005.
Source - Company witness Frank J. Hanley's Rebuttal Testimony, Exhibit___(FJH-24), Sheet 1 of 1.

Rejoinder Testimony
Exhibit No.______(TKW-4)
Sheet 1 of 2

STANDARD &POOR'S	RATINGSDIRECT

Return to Regular Format

Research:
Summary: Southwest Gas Corp.

Publication date: 29-Aug-2005
Primary Credit Analyst(s): Andrew Watt, CFA, New York (1) 212-438-7868; andrew_watt@standardandpoors.com

Credit Rating: BBB-/Stable/--

Rationale

Ratings on Southwest Gas Corp. are based on its business position as a regulated local gas distribution company serving the high-growth service territories of Arizona, Nevada, and, to a lesser extent, California. Ratings also reflect improving operating efficiency and a moderate financial profile. These factors are offset by low customer usage due to its geographic location and challenges associated with improving regulatory treatment in certain jurisdictions.

Las Vegas, Nev.-based Southwest Gas, which has about $1.3 billion of debt, has two business segments, natural gas operations and construction services.

The company provides natural gas to more than 1.66 million customers in Arizona (54%), Nevada (36%), and California (10%). The healthy growth rates in service areas in Nevada (around 6% annual customer additions), Arizona (about 4%), and California (less than 2%) continue to require significant capital outlays. However, only about 60% of capital outlays associated with the growth of its service territory are funded by internal cash flow after dividends.

To internally fund a greater portion of its growth, the company is seeking to improve regulatory treatment, particularly in its largest service territory, Arizona. In Arizona, where the rate of return is below normal, the company has a rate case on file seeking $70.8 million to cover increased costs and improve returns. The discovery phase of the rate case is in process and hearings are scheduled for October 2005. An order is expected by first-quarter 2006. The regulatory environment has improved in Nevada, as evidenced by a rate order approved in August 2004 that contains certain rate-design features that mitigate the effect of weather variation.

Although the business profile benefits from a growing service territory, the cost of creating and maintaining the infrastructure and the regulatory lag associated with recovering these costs in rates has a drag on financial performance. For the 12 months ended June 30, 2005, capital expenditures for natural gas operations were about $240 million. However, internal cash flow after common dividends is projected to fund about 60% of total capital expenditures.

Management's cost-reduction efforts have aided operating performance and somewhat mitigated costs associated with its expanding service territory. Nevertheless, certain credit measures still remain weak for the rating. Adjusted debt leverage is expected to remain high at about 65%. However, cash flow interest coverage of 3.5x is satisfactory for the rating.

Liquidity

The company's liquidity is sufficient, with full access to a $300 million credit facility that expires in April 2010. There is $150 million is available for working capital purposes and $150 million for longer-term funding needs and about $8 million of cash on hand (as of June 30, 2005). With continued healthy customer growth, capital outlays will remain substantial and will require external financing. Capital expenditures are likely to exceed $270 million in 2005. Operating cash flows for the past 12 months were negatively affected by rising natural gas prices as undercollected purchase gas adjustment balances were about $58 million as of June 30, 2005. The company uses short-term borrowings to temporarily finance undercollected balances. Natural gas purchases and capital outlays to service growth in the service territory are the primary draws on liquidity.

Outlook

The stable outlook anticipates steady, gradual improvement in credit measures. Timely rate relief and periodic equity infusions should enhance credit measures. As regulation becomes somewhat more accommodating through favorable rate design changes, credit measures should improve. Ratings are unlikely to be lowered in the foreseeable future. Ratings improvement hinges on achieving better rates of return and rate design improvements in Arizona, as well as maintaining improved regulatory treatment in Nevada.

Comparison of Hill Proxy Group Results vs. Hill Recommendations

	Hill Proxy Group Results	Hill Recommendations
Common Equity Ratio [5-Year Average - 2000-2004]	48.85%*	40.00%
Achieved ROE [5-Year Average - 2000-2004]	10.93%**	9.50%

* Rebuttal Testimony of Theodore K. Wood [Exhibit No. _____ (TKW-2), Sheet 1 of 4

** Direct Testimony of Stephen G. Hill [Exhibit__(SGH-1), Schedule 3, Pages 1-4

EXHIBIT

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Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

MARCIA WEEKS
CHAIRMAN
RENZ D. JENNINGS
COMMISSIONER
DALE H. MORGAN
COMMISSIONER

EXHIBIT
A-42
Admitted

Arizona Corporation Commission
DOCKETED
AUG 31 1990
DOCKETED BY

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS CENTRAL ARIZONA DIVISION (FORMERLY PAPAGO DIVISION).

DOCKET NO. U-1551-89-102

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS SOUTHERN ARIZONA DIVISION (FORMERLY APACHE DIVISION).

DOCKET NO. U-1551-89-103

DECISION NO. 57075

OPINION AND ORDER

DATES OF HEARING:	October 30, 1989 (Public Comments), November 1 and 8, 1989 (Public Comments), November 9, 1989 (Pre-Hearing Conference), November 14, 16, and 17, 1989 (Public Comments), November 20, 1989 (Procedural Conference), November 27, 28, 29, and 30, December 1, 4, 5, 6, 7, 8, 11, 12, and 13, 1989 (Hearing).
PLACE OF HEARING:	Phoenix, Arizona (Hearing) Miami, Casa Grande, Tucson, Douglas, Bisbee, Green Valley, Bullhead City, Yuma, and Sun City, Arizona (Public Comments).
PRESIDING OFFICER:	Beth Ann Burns
IN ATTENDANCE:	Renz D. Jennings, Chairman Marcia Weeks, Commissioner Dale H. Morgan, Commissioner
APPEARANCES:	Mr. Thomas J. Trimble, Senior Vice President and General Counsel, Mr. Andrew Bettwy, Senior Attorney, and Mr. Thomas R. Sheets, Associate General Counsel, on behalf of Southwest Gas Corporation; SNELL & WILMER, by Mr. Steven M. Wheeler and Mr. Thomas L. Mumaw, on behalf of Arizona Public Service Company and Pimalco;

2. **Southern Division**
(000's Omitted)

	Applicant Adjusted	Commission Adjustments	Adjusted Test Year
Oper. Revenues	$57,687	$ 300	$57,987
Oper. Expenses:			
O & M	31,672	(3,604)	28,068
Depr. and Amort.	9,095	(1,565)	7,530
Fed. and St. Inc. Tax	314	3,690	4,004
Other Taxes	7,297	(1,779)	5,518
Loss - Dispos. of Prop.	122	(30)	92
Total Oper. Expenses	48,500	(3,288)	45,212
NET INCOME	$ 9,187	$3,588	$12,775

V. RATE OF RETURN

Three witnesses presented cost of capital analyses to be considered as evidence by the Commission in determining a fair rate of return for purposes of these proceedings. Applicant's witness Laub found the cost of capital to be 11.65% for the Central division and 12.29% for the Southern division. As a result of the study undertaken by Mr. Hill, Staff concluded that 10.37% is a reasonable rate of return for both divisions. RUCO witness Parcell presented testimony supporting 10.89% for the Central division and 11.76% for the Southern division.

A. CAPITAL STRUCTURE

Southwest's actual, consolidated capital structure at December 31, 1988 and the configurations recommended by the parties are as follows:

	Actual	Applicant	Staff	RUCO Central	RUCO Southern
Long-Term Debt	70.60%	50.00%	52.00%	51.74%	42.67%
Short-Term Debt	2.50%		3.00%		
Preferred Stock	3.10%	5.00%	5.00%	8.44%	3.75%
Common Equity	24.70%	45.00%	40.00%	39.82%	53.58%

Although the derivations are quite different, the capital structures sponsored by the parties do share one common trait, each is hypothetical. Applicant developed its recommended capitalization by adjusting the end of test year capital balances for the removal or inclusion, as appropriate, of jurisdictionally-specific and non-utility financings and by exercising judgment to arrive at ratios within a range it found to be reasonable. RUCO accepted Applicant's assignment of the jurisdictional and non-utility financings, but preferred an individual capitalization for each division, with an adjustment to exclude the effects of four debentures issued in late 1986 or early 1987 which, according to RUCO, enabled the purchase of the Bank and retired debt having a lower cost. Staff proposed a capital structure with a maximum equity component of 40%, based upon: the Company's capitalization before its acquisition of PriMerit; a balancing of customer and stockholder interests; a comparison to other gas distribution companies; and the need to maintain the Company's financial integrity.

The Commission customarily employs an actual capital structure to determine the fair value rate of return. In these proceedings, Applicant's actual consolidated capital structure at December 31, 1988 is too heavily leveraged, with over 70% debt, to be representative of operations in the Central and Southern divisions. Southwest's total utility-only capitalization contains over 68% debt and must be similarly rejected. A hypothetical capital structure, therefore, must be imputed to the Company for ratemaking purposes.

Of the capitalizations postulated for the Commission's consideration, the most representative is that offered by Southwest. It is specific to the Company's utility operations in Arizona. It is very close to RUCO's recommendation if calculated on a combined basis for the two divisions - i.e., 49.32% long-term debt, 5.00% preferred and preference stock, and 45.68% common equity. It is supported by industry averages for other gas distribution companies. It properly excludes short-term debt from the capital structure in accordance with prior decisions. See e.g., <u>APS</u>, Decision Nos. 53761 (date), 55228 (October 9, 1986) 55931 (April 1, 1988); and <u>Mountain States Telephone and Telegraph Company</u>, Decision No. 53849 (December 22, 1983). The Commission will adopt the Arizona-specific utility-only capital structure consisting of 50.00% debt, 5.00% preferred and preference stock and 45.00% common equity.

B. **COST OF DEBT AND PREFERRED STOCK**

The parties have recommended that the following cost rates be assigned the long-term debt and preferred and preference stock components of the capital structure:

	Applicant		Staff	RUCO	
	Central	Southern		Central	Southern
Long-Term Debt	10.47%	11.24%	9.75%*	10.55%	10.99%
Preferred Stock	4.40%	9.57%	4.44%	4.40%**	9.57%

* Calculated excluding short-term debt and preferred stock.

** Calculated including preference stock.

In calculating its recommended cost rates, Southwest applied the effective rate method to the debt and preferred and preference stock issuances attributable to each division. Applicant claims this jurisdictional approach ensures that ratepayers in the division which originated the financing will receive its cost rate benefit.

Staff contends the jurisdictionally-specific cost allocation method employed by Applicant produces a higher cost of capital than

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Arizona Corporation Commission

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BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION, FOR A HEARING TO DETERMINE THE EARNINGS OF THE COMPANY, THE FAIR VALUE OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON AND TO APPROVE RATE SCHEDULES.	DOCKET NO. G-01551A-00-0309
LAWRENCE N. SPITZ, ET AL., COMPLAINANTS, vs. SOUTHWEST GAS CORPORATION, RESPONDENTS.	DOCKET NO. G-01551A-00-0127 DECISION NO. 64172 **OPINION AND ORDER**

DATES OF HEARING:	February 22, July 25-27, 30 and 31, 2001
PLACE OF HEARING:	Phoenix, Arizona
ADMINISTRATIVE LAW JUDGE:	Jane L. Rodda
IN ATTENDANCE:	William A. Mundell, Chairman Marc Spitzer, Commissioner
APPEARANCES:	Mr. Andrew Bettwy, on behalf of Southwest Gas Corporation; Mr. Raymond S. Heyman, Roshka Heyman & DeWulf, PLC, on behalf of Tucson Electric Power Company; Mr. Walter Meek, President, Arizona Utility Investors Association; Mr. Scott Wakefield, Chief Counsel, on behalf of the Residential Utility Consumers Office; Mr. Nicholas J. Enoch, Lubin & Enoch, PC, on behalf of Lawrence N. Spitz, State Council of the

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is no evidence that the Test Year experience is an aberration and not reflective of the expense that will be incurred during the period rates will be in effect. Southwest testified that the level of overtime actually experienced during the twelve months ended November 30, 2000 was 7.68 percent, slightly higher than the Test Year level of labor overtime.

Regarding RUCO's removal of half of the payroll costs associated with sales and marketing personnel, Southwest asserts that these individuals were necessary to extend service to the 101,440 new customers enlisted since the Company's last rate case. While these individuals may engage in some marketing activities, they do much more than that, including coordinating the entire process of delivering gas to a specific site. Southwest argues these jobs cannot be eliminated.

We agree with Staff's adjustment for annualizing Test Year end employees and agree that the effect of the 2000 wage increase is known and measurable and should be allowed. The wage increase is applied to Test Year employees who were serving Test Year customers and thus does not result in a mismatch of revenue and expenses. The overtime percentage increased over the three years used in Staff's analysis, and apparently increased slightly in 2000. We agree with Southwest, that in this case, actual Test Year overtime is the more accurate reflection of actual expenses than the averaging methodology employed by Staff. Consequently, we increase Staff's recommended payroll expense by $567,868 to reflect an overtime rate of 7.63 percent. We further agree with the Company that RUCO's proposed removal of half of the costs associated with the sales and marketing staff is not warranted, as these employees are necessary for processing a request for service.

Management Incentive Plan

Certain key management employees are eligible for awards under the Company's Management Incentive Plan ("MIP") if the Company's common stock dividend equals or exceeds the prior year's dividend, and if the Company's performance equals or exceeds a threshold percentage of specific performance targets. There are five performance targets: 1) Southwest's Return on Equity; 2) Return on equity vis-à-vis a peer group return on equity; 3) customer service satisfaction; 4) Southwest's customer-to-employee ratio; and 5) Southwest's customer-to-employee ratio vis-à-vis a peer group ratio.

RUCO proposes that the costs of the MIP be shared equally between ratepayers and limitations on compensation and the exclusion of deferred compensation in the Basic Retirement Plan provided to other employees.

In arguing that the SERP costs should not be borne by ratepayers, RUCO did not ~~focus on the~~ overall compensation package to the Company's top executives. There is no evidence that Southwest's overall compensation package is excessive. We will not remove the SERP from allowed expenses absent such showing.

RUCO proposes to reduce operating expenses by $600,874 to remove Test-Year expenses associated with employee gifts and dinners, an officer retreat and personal use of Company automobiles. RUCO states that the Commission has traditionally disallowed expenses associated with employee parties and events and that costs of vehicles for personal use are simply an additional perk that the Company offers to select employees. RUCO argues these costs are not necessary in the provision of gas service and should not be funded by ratepayers.

Southwest explains that there are two types of employees who drive Company vehicles. Category B employees drive vehicles as a normal part of their job duties and commuting is their only personal use. Pursuant to IRS regulations, these employees have three dollars a day added to their gross income to reflect the commuting value that they receive. The Company benefits from allowing these employees to take their vehicles home as they can travel directly to work sites. The other type of employees who receive vehicles are officer and director level employees who are required to track their vehicle usage between business and personal use. The value of their personal use is included as non-cash compensation in their income. In this case, the use of the vehicle is a component of the employees' overall compensation package. Southwest argues that without performing an analysis of the overall compensation package, such costs cannot be determined to be unreasonable or unnecessary. As to the rest of RUCO's adjustment, Southwest argues that employee recognition awards are necessary to retain valued employees.

We agree with RUCO's adjustments. The Commission historically removes expenses that are not necessary to provide gas service.

RUCO proposes to reduce operating expenses by $106,881 to remove the portion of the American Gas Association ("AGA") dues related to advertising and marketing activities and

RUCO'S RESPONSE

***

THIRD SET OF DATA REQUESTS FROM SOUTHWEST GAS CORPORATION TO THE RESIDENTIAL UTILITY CONSUMER OFFICE (Docket No. G-01551A-04-0876)

3.1 On lines 7 – 8 on page 15 of the Direct Testimony of Mr. Rodney L. Moore, he identifies 37 employees who he states "fill positions whose primary responsibilities include the marketing of gas and gas products." Please explain how Mr. Moore arrived at his conclusion and the resulting recommended disallowance.

Response (Moore):

The Company's response to RUCO's Data Request 2.13 explains the "Sales Incentive Plan", which provides the basis for my disallowance. The actual amount of the disallowance was calculated from the Company's response to RUCO's Data Request 2.08.

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RESIDENTIAL UTILITY CONSUMER OFFICE

1110 WEST WASHINGTON STREET • SUITE 220 • PHOENIX, ARIZONA 85007 • (602) 364-4835 • FAX: (602) 364-4846

August 9, 2005

Mr. Andrew W. Bettwy
Legal Department
Southwest Gas Corporation
P. O. Box 98510
Las Vegas, Nevada 89193-8510

VIA ELECTRONIC MAIL
ORIGINAL VIA U.S. MAIL

Re: Residential Utility Consumer Office's ("RUCO") Response to Southwest Gas Corporation's Third Set of Data Requests ACC Docket No. G-01551A-04-0876

Dear Mr. Bettwy:

Enclosed is RUCO's response to Southwest Gas Corporation's third set of data requests.

If you have any questions, please feel free to contact me.

Sincerely,

Scott S. Wakefield
Chief Counsel

SSW/eg
Enc.

Confidential

Exhibit A-45

Pages 1 - 6

Confidential

Exhibit A-46

Pages 1 - 35

SOUTHWEST GAS CORPORATION
2004 ARIZONA GENERAL RATE CASE
* * *

RESIDENTIAL UTILITY CONSUMER OFFICE
DATA REQUEST NO. RUCO-15
(RUCO-15-1 THROUGH RUCO-15-4)

DOCKET NO.:	G-01551A-04-0876
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	JULY 1, 2005

Request No. RUCO-15-1:

Pipe Replacement -- Please provide for each year 2000 through 2004 the amount of Aldyl A, 1960 steel, and ABS pipe that was replaced. Also provide the accumulated depreciation and deferred taxes for each type pipe for each year.

Respondent: Revenue Requirements

Response:

Attached are schedules and workpapers that calculate the cost of Aldyl A, ABS, and 1960's Steel replacement dollars, accumulated depreciation, and deferred taxes relative to each type of pipe. The pipe footage and resulting cost is for all pipe replaced, and not necessarily for pipe replaced due to defective material or faulty installation practices. For instance, to the extent pipe was replaced pursuant to franchise-related work, the replacement dollars are contained in the attached analysis.

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SOUTHWEST GAS CORPORATION
ARIZONA
PIPE REPLACEMENT
FOR THE YEARS 2000 THROUGH AUGUST 2004
PLASTIC PIPE

Description	2000	2001	2002	2003	2004	Total
			Mains			
ABS						
Footage Replaced	34	311	0	14,979	2,964	18,288
Cost Per Foot	13.50	14.93	0.00	20.13	22.91	
Replacement Cost	$ 459	$ 4,643	$ 0	$ 301,527	$ 67,905	$ 374,535
Aldyl A						
Footage Replaced	11,664	17,934	12,235	39,320	20,682	101,835
Cost Per Foot	12.83	19.71	18.10	23.86	24.42	
Replacement Cost	$ 149,649	$ 353,479	$ 221,454	$ 938,175	$ 505,054	$ 2,167,811
			Services			
ABS						
Footage Replaced	95	0	0	19		114
Cost Per Foot	16.55	0.00	0.00	15.61	0.00	
Replacement Cost	$ 1,572	$ 0	$ 0	$ 297	$ 0	$ 1,869
Aldyl A						
Footage Replaced	15,523	11,685	19,652	14,013	8,107	68,980
Cost Per Foot	18.16	16.10	23.54	17.08	17.13	
Replacement Cost	$ 281,898	$ 188,129	$ 462,608	$ 239,342	$ 138,873	$ 1,310,849

DOCKET NO. G-01551A-04-0876
RUCO-15-1
SHEET 2 OF 8

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF DISSALLOWED GROSS PLANT AND RELATED DEPRECIATION EXPENSE
FOR THE YEARS 2000 THROUGH AUGUST 2004
ALDYL ABS PIPE
RESPONSE TO RUCO DATA REQUEST NO. 15-1

Description	2000	2001	2002	2003	2004	Total
Mains						
Aldyl ABS						
Footage Replaced	34	311	0	14,979	2,964	18,288
Cost Per Foot	$ 13.50	$ 14.93	$ 0.00	$ 20.13	$ 22.91	$
Replacement Cost	$ **459**	$ **4,643**	$ **0**	$ **301,527**	$ **67,905**	$ **374,535**
Services						
Aldyl ABS						
Footage Replaced	95	0	0	19	0	$ 114
Cost Per Foot	16.55	0.00	0.00	15.61	0.00	
Replacement Cost	$ **1,572**	$ **0**	$ **0**	$ **297**	$ **0**	$ **1,869**
Total Mains & Services	$ 2,031	$ 4,643	$ 0	$ 301,824	$ 67,905	$ 376,404
Cummulative	$ 2,031	$ 6,674	$ 6,674	$ 308,498	$ 376,404	$

Depreciation Expense

	2000	2001	2002	2003	2004	Total
Mains						
Aldyl ABS	3.82%					
Annual Expense	18	177	0	11,518	2,594	
Monthly Expense	2	15	0	960	216	
Months	50	38	26	14	4	
Expense 2000 - 2004	75	561	0	13,438	865	14,938
Services						
Aldyl ABS	5.30%					
Annual Expense	83	0	0	16	0	
Monthly Expense	7	0	0	1	0	
Months	50	38	26	14	4	
Expense 2000 - 2004	346	0	0	19	0	365
Total Mains & Services	421	561	0	13,456	865	15,302

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF DISSALLOWED DEFERRED TAX
FOR THE YEARS 2000 THROUGH AUGUST 2004
ALDYL ABS PIPE
RESPONSE TO RUCO DATA REQUEST NO. 15-1

	2000	2001	2002	2003	2004
	1	2	3	4	5
Regular MACRS	3.7500%	7.2190%	6.6770%	6.1770%	5.7130%
30% Bonus Vintage 2002			32.6250%	5.0530%	4.6740%
50% Bonus Vintages 2003 and 2004				51.8750%	3.6100%

Aldyl ABS

		2000	2001	2002	2003	2004	Book Cost			Bk Dep					Def Tax	Net Rate Base
MAINS		459	4,643	0	301,527	67,905	374,535			(14,937)					(67,084)	292,513
							Federal Depreciation	State Depreciation	Months 3.82%	Book Depreciation	Federal DFIT Excess Tax Depreciation	Federal DFIT DFIT 35.00%	Arizona DSIT Excess Tax Depreciation	Arizona DSIT DSIT 4.53%	Total Deferred Taxes	
1	2000	17	33	31	28	26	136	136	50	73	63	(22)	63	(3)	**(25)**	
2	2001		174	335	310	287	1,106	1,106	38	562	544	(191)	544	(25)	**(215)**	
3	2002			0	0	0	0	0	26	0	0	0	0	0	**0**	
4	2003				156,417	10,885	167,302	33,075	14	13,438	153,864	(53,853)	19,636	(889)	**(54,742)**	
5	2004					35,226	35,226	2,546	4	865	34,361	(12,026)	1,682	(76)	**(12,103)**	
Federal Tax Depreciation		17	207	366	156,756	46,424	203,770	36,863		14,937	188,833	(66,091)		(993)	**(67,084)**	

Aldyl ABS

		2000	2001	2002	2003	2004	Book Cost			Bk Dep					Def Tax	
SERVICES		1,572	0	0	297	0	1,869			(366)					(98)	1,405
							Federal Depreciation	State Depreciation	Months 5.30%	Book Depreciation	Federal DFIT Excess Tax Depreciation	Federal DFIT DFIT 35.00%	Arizona DSIT Excess Tax Depreciation	Arizona DSIT DSIT 4.53%	Total Deferred Taxes	
1	2000	59	114	105	97	90	464	464	50	347	117	(41)	117	(5)	**(46)**	
2	2001		0	0	0	0	0	0	38	0	0	0	0	0	**0**	
3	2002			0	0	0	0	0	26	0	0	0	0	0	**0**	
4	2003				154	11	165	33	14	18	146	(51)	14	(1)	**(52)**	
5	2004					0	0	0	4	0	0	0	0	0	**0**	
Federal Tax Depreciation		59	114	105	251	101	629	497		366	263	(92)		(6)	**(98)**	

DOCKET NO. G-01551A-04-0876
RUCO-15-1
SHEET 3 OF 8

DOCKET NO. G-01551A-04-0876
RUCO-15-1
SHEET 4 OF 8

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF DISSALLOWED GROSS PLANT AND RELATED DEPRECIATION EXPENSE
FOR THE YEARS 2000 THROUGH AUGUST 2004
ALDYL AA PIPE
RESPONSE TO RUCO DATA REQUEST NO. 15-1

Description	2000	2001	2002	2003	2004	Total
Mains						
Aldyl AA						
Footage Replaced	11,664	17,934	12,235	39,320	20,682	101,835
Cost Per Foot	$ 12.83	$ 19.71	$ 18.10	$ 23.86	$ 24.42	$
Replacement Cost	**$ 149,649**	**$ 353,479**	**$ 221,454**	**$ 938,175**	**$ 505,054**	**$ 2,167,811**
Services						
Aldyl AA						
Footage Replaced	15,523	11,685	19,652	14,013	8,107	$ 68,980
Cost Per Foot	18.16	16.10	23.54	17.08	17.13	
Replacement Cost	$ 281,898	$ 188,129	$ 462,608	$ 239,342	$ 138,873	$ 1,310,849
Total Mains & Services	$ 431,547	$ 541,608	$ 684,062	$ 1,177,517	$ 643,927	$ 3,478,661
Cummulative	$ 431,547	$ 973,154	$ 1,657,216	$ 2,834,733	$ 3,478,661	$

Depreciation Expense

	2000	2001	2002	2003	2004	Total
Mains						
Aldyl AA	3.82%					
Annual Expense	5,717	13,503	8,460	35,838	19,293	
Monthly Expense	476	1,125	705	2,987	1,608	
Months	50	38	26	14	4	
Expense 2000 - 2004	23,821	42,760	18,330	41,811	6,431	133,152
Services						
Aldyl AA	5.30%					
Annual Expense	14,941	9,971	24,518	12,685	7,360	
Monthly Expense	1,245	831	2,043	1,057	613	
Months	50	38	26	14	4	
Expense 2000 - 2004	62,254	31,575	53,122	14,799	2,453	164,204
Total Mains & Services	86,075	74,334	71,452	56,610	8,884	297,356

DOCKET NO. G-01551A-04-0876
RUCO-15-1
SHEET 5 OF 8

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF DISSALLOWED DEFERRED TAX
FOR THE YEARS 2000 THROUGH AUGUST 2004
ALDYL AA PIPE
RESPONSE TO RUCO DATA REQUEST NO. 15-1

	2000	2001	2002	2003	2004
	1	2	3	4	5
Regular MACRS	3.7500%	7.2190%	6.6770%	6.1770%	5.7130%
30% Bonus Vintage 2002			32.6250%	5.0530%	4.6740%
50% Bonus Vintages 2003 and 2004				51.8750%	3.6100%

Aldyl AA

		2000	2001	2002	2003	2004	Book Cost			Bk Dep					Def Tax	Net Rate Base
	MAINS	149,649	353,479	221,454	938,175	505,054	2,167,811			(133,150)					(312,132)	1,722,530
							Federal Depreciation	State Depreciation	Months 3.82%	Book Depreciation	Federal DFIT Excess Tax Depreciation	DFIT 35.00%	Arizona DSIT Excess Tax Depreciation	DSIT 4.53%	Total Deferred Taxes	
1	2000	5,612	10,803	9,992	9,244	8,549	44,200	44,200	50	23,819	20,381	(7,133)	20,381	(923)	(8,057)	
2	2001		13,255	25,518	23,602	21,834	84,209	84,209	38	42,759	41,450	(14,508)	41,450	(1,877)	(16,385)	
3	2002			72,249	11,190	10,351	93,790	39,078	26	18,329	75,461	(26,411)	20,749	(940)	(27,351)	
4	2003				486,678	33,868	520,547	102,908	14	41,811	478,735	(167,557)	61,097	(2,767)	(170,325)	
5	2004					261,997	261,997	18,940	4	6,431	255,566	(89,448)	12,509	(567)	(90,015)	
Federal Tax Depreciation		5,612	24,059	107,759	530,714	336,600	1,004,743	289,335		133,150	871,594	(305,058)		(7,074)	(312,132)	

Aldyl AA

		2000	2001	2002	2003	2004	Book Cost			Bk Dep					Def Tax	Net Rate Base
	SERVICES	281,898	188,129	462,608	239,342	138,873	1,310,849			(164,202)					(131,110)	1,015,537
							Federal Depreciation	State Depreciation	Months 5.30%	Book Depreciation	Federal DFIT Excess Tax Depreciation	DFIT 35.00%	Arizona DSIT Excess Tax Depreciation	DSIT 4.53%	Total Deferred Taxes	
1	2000	10,571	20,350	18,822	17,413	16,105	83,261	83,261	50	62,252	21,009	(7,353)	21,009	(952)	(8,305)	
2	2001		7,055	13,581	12,561	11,621	44,818	44,818	38	31,574	13,244	(4,635)	13,244	(600)	(5,235)	
3	2002			150,926	23,376	21,622	195,924	81,632	26	53,123	142,801	(49,980)	28,509	(1,291)	(51,272)	
4	2003				124,159	8,640	132,799	26,253	14	14,799	118,000	(41,300)	11,454	(519)	(41,819)	
5	2004					72,040	72,040	5,208	4	2,453	69,587	(24,355)	2,754	(125)	(24,480)	
Federal Tax Depreciation		10,571	27,405	183,329	177,508	130,028	528,842	241,172		164,202	364,640	(127,624)		(3,486)	(131,110)	

SOUTHWEST GAS CORPORATION
ARIZONA
PIPE REPLACEMENT
FOR THE YEARS 2000 THROUGH AUGUST 2004
1960'S STEEL

Description	2000	2001	2002	2003	2004	Total
Mains						
Steel Main (All)						
Footage Replaced	60,036	52,108	90,110	192,835	61,564	456,653
Cost Per Foot	$ 20.94	$ 19.81	$ 28.59	$ 25.70	$ 45.58	
Replacement Cost	$ 1,257,154	$ 1,032,259	$ 2,576,245	$ 4,955,860	$ 2,806,087	$ 12,627,605
Steel 1960's (40%)						
Footage Replaced	24,014	20,843	36,044	77,134	24,626	182,661
Cost Per Foot	$ 20.94	$ 19.81	$ 28.59	$ 25.70	$ 45.58	
1960's Replacement Cost	$ 502,862	$ 412,904	$ 1,030,498	$ 1,982,344	$ 1,122,435	$ 5,051,042
Services						
Steel Services (all)						
Footage Replaced	29,707	41,220	46,247	34,176	29,740	181,090
Cost Per Foot	$ 17.98	$ 17.58	$ 19.51	$ 16.27	$ 17.32	
Replacement Cost	$ 534,132	$ 724,648	$ 902,279	$ 556,044	$ 515,097	$ 3,232,199
Steel 1960's (40%)						
Footage Replaced	11,883	16,488	18,499	13,670	11,896	72,436
Cost Per Foot	$ 17.98	$ 17.58	$ 19.51	$ 16.27	$ 17.32	
1960's Replacement Cost	$ 213,653	$ 289,859	$ 360,912	$ 222,417	$ 206,039	$ 1,292,880

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF DISSALLOWED GROSS PLANT AND RELATED DEPRECIATION EXPENSE
FOR THE YEARS 2000 THROUGH AUGUST 2004
1960's STEEL
RESPONSE TO RUCO DATA REQUEST NO. 15-1

Description	2000	2001	2002	2003	2004	Total
Mains						
1960's Steel						
Footage Replaced	24,014	20,843	36,044	77,134	24,626	182,661
Cost Per Foot	$ 20.94	$ 19.81	$ 28.59	$ 25.70	$ 45.58	$
Replacement Cost	**$ 502,862**	**$ 412,904**	**$ 1,030,498**	**$ 1,982,344**	**$ 1,122,435**	**$ 5,051,042**
Services						
1960's Steel						
Footage Replaced	11,883	16,488	18,499	13,670	11,896	$ 72,436
Cost Per Foot	17.98	17.58	19.51	16.27	17.32	
Replacement Cost	**$ 213,653**	**$ 289,859**	**$ 360,912**	**$ 222,417**	**$ 206,039**	**$ 1,292,880**
Disallowance percent	17.5%	16.5%	15.5%	14.5%	13.5%	
Disallowance	$ 37,389	$ 47,827	$ 55,941	$ 32,251	$ 27,815	$ 201,223
Total Mains & Services	$ 37,389	$ 47,827	$ 55,941	$ 32,251	$ 27,815	$ 201,223
Cummulative	$ 37,389	$ 85,216	$ 141,157	$ 173,408	$ 201,223	$

Depreciation Expense

	2000	2001	2002	2003	2004	Total
Mains						
1960's Steel	3.82%					
Annual Expense	19,209	15,773	39,365	75,726	42,877	
Monthly Expense	1,601	1,314	3,280	6,311	3,573	
Months	50	38	26	14	4	
Expense 2000 - 2004	80,038	49,948	85,291	88,347	14,292	317,916
Services						
1960's Steel	5.30%					
Annual Expense	11,324	15,363	19,128	11,788	10,920	
Monthly Expense	944	1,280	1,594	982	910	
Months	50	38	26	14	4	
Expense 2000 - 2004	47,183	48,650	41,444	13,753	3,640	154,670
Total Mains & Services	127,221	98,597	126,735	102,100	17,932	472,585

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF DISSALLOWED DEFERRED TAX
FOR THE YEARS 2000 THROUGH AUGUST 2004
1960'S STEEL
RESPONSE TO RUCO DATA REQUEST NO. 15-1

		2000	2001	2002	2003	2004	Book Cost			Bk Dep					Def Tax	Net Rate Base
		1	2	3	4	5										
	Regular MACRS	3.7500%	7.2190%	6.6770%	6.1770%	5.7130%										
	30% Bonus Vintage 2002			32.6250%	5.0530%	4.6740%										
	50% Bonus Vintages 2003 and 2004				51.8750%	3.6100%										
	Aldyl ABS															
	MAINS	502,862	412,904	1,030,498	1,982,344	1,122,435	5,051,042			(317,916)					(733,426)	3,999,700
							Federal Depreciation	State Depreciation	Months 3.82%	Book Depreciation	Federal DFIT Excess Tax Depreciation	Federal DFIT DFIT 35.00%	Arizona DSIT Excess Tax Depreciation	Arizona DSIT DSIT 4.53%	Total Deferred Taxes	
1	2000	18,857	36,302	33,576	31,062	28,728	148,525	148,525	50	80,039	68,486	(23,970)	68,486	(3,102)	**(27,072)**	
2	2001		15,484	29,808	27,570	25,505	98,366	98,366	38	49,948	48,418	(16,946)	48,418	(2,193)	**(19,139)**	
3	2002			336,200	52,071	48,165	436,436	181,842	26	85,291	351,146	(122,901)	96,551	(4,373)	**(127,274)**	
4	2003				1,028,341	71,563	1,099,903	217,443	14	88,346	1,011,557	(354,045)	129,097	(5,847)	**(359,892)**	
5	2004					582,263	582,263	42,091	4	14,292	567,971	(198,790)	27,799	(1,259)	**(200,049)**	
	Federal Tax Depreciation	18,857	51,785	399,584	1,139,043	756,225	2,365,494	688,268		317,916	2,047,578	(716,652)		(16,774)	**(733,426)**	

		2000	2001	2002	2003	2004	Book Cost			Bk Dep					Def Tax	Net Rate Base
	Aldyl ABS															
	SERVICES	213,653	289,859	360,912	222,417	206,039	1,292,880			(154,667)					(129,542)	1,008,670
							Federal Depreciation	State Depreciation	Months 5.30%	Book Depreciation	Federal DFIT Excess Tax Depreciation	Federal DFIT DFIT 35.00%	Arizona DSIT Excess Tax Depreciation	Arizona DSIT DSIT 4.53%	Total Deferred Taxes	
1	2000	8,012	15,424	14,266	13,197	12,206	63,104	63,104	50	47,182	15,923	(5,573)	15,923	(721)	**(6,294)**	
2	2001		10,870	20,925	19,354	17,905	69,053	69,053	38	48,648	20,405	(7,142)	20,405	(924)	**(8,066)**	
3	2002			117,747	18,237	16,869	152,853	63,686	26	41,445	111,409	(38,993)	22,242	(1,007)	**(40,000)**	
4	2003				115,379	8,029	123,408	24,397	14	13,753	109,655	(38,379)	10,644	(482)	**(38,862)**	
5	2004					106,883	106,883	7,726	4	3,640	103,243	(36,135)	4,086	(185)	**(36,320)**	
	Federal Tax Depreciation	8,012	26,293	152,938	166,167	161,891	515,302	227,967		154,667	360,635	(126,222)		(3,320)	**(129,542)**	

Oct-07-05 02:41am From- T-657 P.01/01 F-037 A-48

SWEEP

Southwest Energy Efficiency Project

A Project of the American Council for an Energy-Efficient Economy and the Land & Water Fund of the Rockies

04 JUL 27 AM 10: 14

July 26, 2004

Commissioners Soderberg, Chanos, and Linvill
Public Utilities Commission of Nevada
State of Nevada Capital Plaza
1150 East William Street
Carson City, Nevada 89701

Attn. Ms. Crystal Jackson, Commission Secretary

Dear Members of the Public Utilities Commission of Nevada,

The Southwest Energy Efficiency Project (SWEEP) is a non-profit public interest organization dedicated to advancing energy efficiency in six states including Nevada. SWEEP would like to submit a brief comment regarding the Southwest Gas Corporation's general rate case, Docket No. 04-3011. In particular, SWEEP would like to support the company's proposal to decouple revenues from gas sales levels, also know as the Margin per Customer Balancing Provision or MCB.

SWEEP supports this proposal because we believe it could facilitate gas conservation efforts on the part of Southwest Gas Corporation. The gas company should be more willing to actively promote energy efficiency and conservation among its customers if the company does not lose revenue from stimulating more efficient gas use. Adopting the decoupling mechanism alone does not necessarily stimulate additional gas conservation programs by the gas company, but it does remove the disincentive to doing so.

In addition, we encourage the PUC of Nevada to address the issue of gas conservation programs in a separate docket. Gas utilities in a number of states operate cost-effective gas conservation programs for their customers. These programs include home and business energy audits, incentives for purchase of high efficiency heating equipment, incentives for home or commercial building retrofit, and incentives for efficient new construction. Some of the best gas utility energy efficiency programs and best state polices on gas conservation were featured in a recent report by the American Council for an Energy-Efficient Economy titled "Responding to the Natural Gas Crisis: America's Best Natural Gas Energy Efficiency Programs" (http://aceee.org/pubs/u035.htm).

SWEEP has no position on other matters in Docket No. 04-3011. Thank you for considering our views.

Sincerely yours,

Howard Geller

Howard Geller
Executive Director

EXHIBIT
tabbies
A-48
Admitted

2260 Baseline #200 • Boulder, CO 80302 • tel: 303.444.1188 ext. 230 • fax: 303.786.8054 • www.swenergy.org

EXHIBIT
A-49
Admitted

SOUTHWEST GAS CORPORATION
ILLUSTRATIVE APPLICATION OF CONSERVATION MARGIN TRACKER

Line No.	Description	Year One: Customer One Who Does Not Implement Conservation	Year One: Customer Two Who Does Implement Conservation	Year Two: Customer One Who Does Not Implement Conservation	Year Two: Customer Two Who Does Implement Conservation	Customer One Total	Customer Two Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	Average Annual Residential Use per Customer Used For Rate Design	347	347	347	347	694	694	1
2	Change in Average Use	0	(20)	0	(20)	0	(40)	2
3	Actual Use Per Customer	347	327	347	327	694	654	3
4	Southwest 2nd Block Commodity Rate per Therm Margin Rate	$ 0.25000	$ 0.25000	$ 0.25000	$ 0.25000			4
5	Gas Cost	$ 0.65000	$ 0.65000	$ 0.65000	$ 0.65000			5
6	CMT Surcharge	n/a	n/a	$ 0.00742 [1]	$ 0.00742 [1]			6
7	Savings Related to Conservation Margin (Line 2 X Line 4)	$ -	$ (5.00)	$ -	$ (5.00)	$ -	$ (10.00)	7
8	Gas Cost (Line 2 X Line 5)	0.00	(13.00)	0.00	(13.00)	0.00	(26.00)	8
9	CMT Surcharge (Line 3 X Line 6)	0.00	0.00	2.57	2.43	2.57	2.43	9
10	Total Savings (Line 7 + Line 8 + Line 9)	$ -	$ (18.00)	$ 2.57	$ (15.57)	$ 2.57	$ (33.57)	10

[1] CMT surcharge equal to $(5.00) divided by 674 therms.

EXHIBIT
A-51
Admitted

SOUTHWEST GAS CORPORATION

SUMMARY OF RISK UNDER SOUTHWEST GAS' CURRENT AND ALL PARTIES' PROPOSED RESIDENTIAL RATE DESIGNS

Description	SWG Current	SWG w/ CMT	SWG no CMT	Staff	RUCO
Marginal Price	$.40344	$.25000	$.15000	$.50100	$.49495
10 Therm Change in Use	$4.03	$2.50	$1.50	$5.01	$4.95

RUCO

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-04-0876

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 26, 2005

Admitted

EXHIBIT

RUCO 1

10/06/05

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and your qualifications in the field of utilities regulation.

A. Appendix I, which is attached to this testimony, describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Southwest Gas Corporation's ("SWG" or "Company") application ("Application") for a permanent rate increase, which was filed with the Arizona Corporation Commission ("ACC" or "Commission") on December 9, 2004. The Company is based in Las Vegas, NV, and is publicly traded on the New York Stock Exchange ("NYSE"). SWG is the dominant local distribution company ("LDC") in Arizona and also provides natural gas distribution services in the states of California and Nevada. The Company has chosen the twelve-month period ended August 31, 2004 as the test year ("Test Year") for this proceeding.

Q. Please explain your role in RUCO's analysis of SWG's Application.

A. I reviewed SWG's Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity, preferred equity and long-term debt. The recommendations contained in this testimony are based on information obtained from the Company's Application and on market-based research that I conducted during my cost of capital analysis.

Q. Were you also responsible for conducting an analysis of SWG's proposed revenue level, rate base and rate design?

A. No. Those issues will be addressed in the direct testimony of RUCO witnesses Rodney L. Moore and Marylee Diaz Cortez, C.P.A., the chief of RUCO's Accounting & Rates section. Mr. Moore will sponsor RUCO's recommended levels of required revenue, rate base and rate design. Ms. Diaz Cortez will provide testimony on the Company-proposed conservation margin tracker ("CMT") mechanism and the conceptual concepts that are employed in RUCO's recommended rate design. Both Mr. Moore and Ms. Diaz Cortez will provide testimony on specific operating expense and rate base adjustments.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into three sections. First, I will present the findings of my cost of equity capital analysis, that utilized both the discounted cash flow ("DCF") method, which I believe is the most reliable methodology and the one that I have generally placed the most emphasis on, and the capital asset pricing model ("CAPM"), which I have normally relied on as a check of my DCF results and have also used to make adjustments to my DCF results in certain instances. These are the two most commonly used methods for calculating the cost of equity capital in rate case proceedings and are generally regarded as the most reliable[1]. In this first section I will also provide a brief overview of the current economic climate that SWG is operating in. Second, I will compare my recommended capital structure with the Company-proposed capital structure. Third, I will comment on SWG's cost of capital testimony.

[1] A. Lawrence Kolbe and James A Read Jr., The Cost of Capital – Estimating the Rate of Return for Public Utilities, The MIT Press: Cambridge, Massachusetts, 1984, pp. 35-94.

Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of SWG, I am making the following recommendations:

<u>Cost of Equity Capital</u> – I am recommending a 10.15 percent cost of equity capital. This 10.15 percent figure reflects an upward adjustment of 124 basis points to the results derived from my DCF analysis and is 25 basis points lower than the upper range of my estimates obtained from both the DCF and CAPM methodologies.

<u>Cost of Preferred Equity</u> – I am recommending that the Commission adopt an 8.20 percent cost of preferred equity. This figure represents the effective cost of SWG's $100 million issue of trust originated preferred securities ("TOPrS").

<u>Cost of Debt</u> – I am recommending that the Commission adopt a 7.49 percent cost of long-term debt. This is based on my review of the effective costs associated with SWG's various bond issues and credit facilities.

Capital Structure – I am recommending that the Commission adopt the Company-proposed hypothetical capital structure of 53 percent debt, 42 percent common equity and 5 percent preferred equity.

Cost of Capital – Based on the results of my recommended capital structure, cost of common equity, cost of preferred equity and cost of long-term debt analyses, I am recommending an 8.64 percent cost of capital for SWG. This figure represents the weighted cost of the Company's common equity, preferred equity, and long-term debt.

Q. Why do you believe that your recommended 8.64 percent cost of capital is an appropriate rate of return for SWG to earn on its invested capital?

A. The 8.64 percent cost of capital figure that I have recommended meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case guarantees a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as SWG, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your recommended cost of equity capital for SWG?

A. Based on the results of my DCF and CAPM analyses, which ranged from 8.82 percent to 10.39 percent, I am recommending a 10.15 percent cost of equity capital for SWG. My recommended 10.15 percent figure represents a 25 basis point reduction to the extreme upper range of the results that were derived from my cost of common equity analysis.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate SWG's cost of equity capital.

A. The DCF method employs a stock valuation model that is often referred to as either the constant growth valuation model or the Gordon[2] model. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the

[2] Named after Dr. Myron J. Gordon, the professor of finance who developed the model.

dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = (D_1 \div P_0) + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$D_1 \div P_0$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth.

This formula is the basis for the standard growth valuation model that I used to determine SWG's cost of equity capital. It is similar to the model that was used by the Company.

Q. In determining the rate of future dividend growth for SWG, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as g = b x r.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[3]

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

[3] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as $g = b \times r$, is also referred to as the internal or sustainable growth rate.

...

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[4] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[5] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rates for earnings and dividends, displayed in the last column, are 16.20 percent. If this rate were to be

[4] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[5] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation. Although it is not illustrated in Mr. Hill's hypothetical example, a change in only the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[6] Dr. Myron Gordon, the individual responsible for the development of the DCF or constant growth model, identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where: g = DCF expected growth rate,

b = the earnings retention ratio,

r = the return on common equity,

s = the fraction of new common stock sold that accrues to a current shareholder, and

[6] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

	v	=	funds raised from the sale of stock as a fraction of existing equity.
and	v	=	1 - [(BV) ÷ (MP)]
where:	BV	=	book value per share of common stock, and
	MP	=	the market price per share of common stock.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M ÷ B) + 1] ÷ 2.

A. In theory, the market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M ÷ B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. In determining your dividend growth rate estimate, you analyzed the data on ten natural gas LDC's. Why did you use this methodology as opposed to a direct analysis of SWG?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company. Although SWG is publicly traded on the NYSE, SWG's Arizona operations are not. Because of this situation, I created a proxy that includes ten publicly traded natural gas providers that have similar risk characteristics to SWG in order to derive a cost of common equity for the Company.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the ten LDC's that make up your proxy for SWG?

A. Each of the LDC's used in the proxy are followed by The Value Line Investment Survey ("Value Line") and comprise Value Line's natural gas (distribution) industry segment of the U.S. economy. All of the companies in the proxy are engaged in the provision of regulated natural gas distribution services. Attachment A of my testimony contains Value Line's most recent evaluation of the natural gas (distribution) industry.

Q. Are these the same natural gas providers that the Company's cost of capital witness used in SWG's application?

A. Yes, the Company's cost of capital witness, Mr. Frank J. Hanley, included the same natural gas providers in one of two proxy groups that he used for his cost of common equity analysis. The proxy group that contained the ten LDC's that I have used also included a company known as Energen Corporation, which I have decided to exclude from my proxy.

Q. Why did you exclude Energen Corporation from your proxy group?

A. Energen Corporation derives a large portion of its total revenues from oil and natural gas drilling and exploration in areas such as the San Juan (northwestern New Mexico) and Permian (West Texas) basins in addition to operating a LDC in Alabama. Because of this distinction and the fact that Energen is included in Value Line's natural gas (diversified) industry as opposed to the aforementioned natural gas (distribution) industry, I have decided not to include it in my proxy.

Q. Please describe the ten LDC's that make up your sample proxy.

A. The ten LDC's included in my proxy (and their NYSE ticker symbols) are AGL Resources, Inc. ("ATG"), Cascade Natural Gas Corporation ("CGC"), KeySpan Corp. ("KSE"), Laclede Group, Inc. ("LG"), Nicor Inc. ("GAS"), Northwest Natural Gas Co. ("NWN"), Peoples Energy Corporation ("PGL"), Piedmont Natural Gas Company ("PNY") South Jersey Industries, Inc. ("SJI") and WGL Holdings, Inc. ("WGL").

The ten LDC's listed above provide natural gas service to customers in the Northeast (i.e. KSE which serves New York and New England), the Middle Atlantic region (i.e. SJI which serves southern New Jersey and WGL which serves the Washington D.C. metro area), the Southeast (i.e. ATG which serves Atlanta, Ga., Virginia and Tennessee and PNY which also serves Tennessee and the Carolinas) the Midwest (i.e. PGL and GAS which provide service to Chicago and its suburbs respectively, and LG which serves the St. Louis area), and the Pacific Northwest (i.e. CGC and NWN which serve Washington state and Oregon). Attachment B of my testimony contains Value Line's latest projections on the ten LDC's that I have included in my proxy.

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5, titled Dividend Growth Components, provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the sample for the period 2000 to 2004. Schedule WAR-5 also includes Value Line's projected 2005, 2006, and 2008-2010 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use AGL Resources, Inc., NYSE symbol ATG, as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (page 9) to multiply ATG's earned return on common equity by its earnings retention ratio for each year 2000 through 2004 to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the 2005 internal growth rate and projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, ATG's average internal growth rate of 4.64% over the 2000 - 2004 time frame reflects a steady upward trend that occurred in the first four years of the observation period. From 2000 to 2003 internal growth increased from 1.87% to 6.53%. Internal growth then decreased to 5.45% in 2004. Value

Line is predicting successive increases to 5.53% in 2005, 5.65% in 2006, and 5.85% during the 2008-10 time frame. Despite recent adverse rate request rulings by the Georgia PSC, I believe that a 6.00 percent rate of growth is within the realm of possibility when Value Line's long-term 5.00% earnings, 3.50% dividend, and 8.00% book value growth projections are taken into consideration (Schedule WAR-6).

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 illustrates that the number of ATG shares outstanding increased from 54.00 million to 76.70 million during the 2000 to 2004 time frame. Value Line is predicting that this trend will slow to a level of 77.20 million in 2005 before reaching 78.00 million during the 2008-10 period. Based on this data, I believe that a 0.50% growth in shares is not unreasonable for ATG. My final dividend growth rate estimate for ATG is 6.22 percent (6.00 percent internal + 0.22 percent external) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average dividend growth rate estimate using the DCF model for the sample LDC's?

A. Based on the DCF model, my average dividend growth rate estimate is 4.76 percent as displayed on Page 1 of Schedule WAR-4.

Q. How does your average dividend growth rate compare to the growth rate data of other publicly traded firms?

A. Overall my estimate of 4.76 percent is higher than the projections of analysts at Value Line but lower than the expectations of brokerages that are surveyed by Zacks Investment Research, Inc. ("Zacks"). Schedule WAR-6 compares my sustainable growth estimates with the five-year projections of both Zacks and Value Line. The 4.76 percent estimate that I have calculated is 111 basis points lower than the projected 5-year EPS average of 5.87 percent by Zacks (as can be seen in Attachment C, Zack's five-year outlook for the natural gas industry as a whole is 8.00 percent) and 41 basis points higher than the 4.35 percent by Value Line (which is an average of projected earnings per share, dividends per share and book value per share). My 4.76 percent estimate is 112 basis points higher than the 3.63 percent 5-year compound historical average also displayed in Schedule WAR-6. This indicates that investors are expecting increased performance from LDC's in the future. On balance, I would say my 4.76 percent estimate is a fair representation of the growth projections that are available to the investing public.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period (through June 2006), which appeared in the most recent Ratings and Reports natural gas (distribution) industry updates of <u>The Value Line</u>

Investment Survey (Attachment B). I then divided that figure by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the ten utilities in my proxy for the period May 9, 2005 to July 1, 2005. My analysis produced an average dividend yield of 4.15 percent for the ten LDC's included in my sample.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the LDC's included in your sample?

A. As shown in Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 8.91 percent.

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind the capital asset pricing model ("CAPM") and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe, Ph.D.[7] The CAPM model is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[8] In this regard, CAPM can help an investor to

[7] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[8] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns

determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification. Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\,ß\,(r_m - r_f)\,]$$

where: k = cost of capital of a given security,

r_f = risk-free rate of return,

$ß$ = beta coefficient, a statistical measurement of a security's systematic risk,

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on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

r_m = average market return (e.g. S&P 500), and

$r_m - r_f$ = market risk premium.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used a six-week average on a 91-day Treasury Bill ("T-Bill") rate.[9] This resulted in a risk-free (r_f) rate of return of 3.04 percent.

Q. Why did you use the short-term T-Bill rate as opposed to the yield on an intermediate 5-year Treasury note or a long-term 30-year Treasury bond?

A. Because a 91-day T-Bill presents the lowest possible total risk to an investor. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[10] a true rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the true rate of interest is subtracted from the total treasury yield, all that remains is the inflationary

[9] A six-week average was computed for the current rate using 91-day T-Bill quotes listed in Value Line's Selection and Opinion newsletter from June 10, 2005 to July 15, 2005.

[10] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the true rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my testimony, this compensation translates into higher rates of returns to the investor. Since a 91-day T-Bill presents the lowest possible total risk to an investor, it more closely meets the definition of a risk-free rate of return and is the more appropriate instrument to use in a CAPM analysis.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical returns on the S&P 500 index from 1926 to 2004 as the proxy for the market rate of return (r_m). The risk premium (r_m - r_f) that results by using the geometric mean calculation for r_m is equal to 7.36 percent (10.40% - 3.04% = 7.36%). The risk premium that results by using the arithmetic mean calculation for r_m is 9.36 percent (12.40% - 3.04% = 9.36%).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the LDC's used in my sample, were calculated by Value Line and were current as of June 17, 2005. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the LDC's included in my sample ranged from 0.60 to 1.10 with an average beta of 0.79.

Q. What are the results of your CAPM analysis?

A. As shown on Pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean for r_m results in an average expected return of 8.82 percent. My calculation using the arithmetic mean results in an average expected return of 10.39 percent.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF	8.91%
CAPM	8.82% – 10.39%

Based on these results, my best estimate of an appropriate range for the cost of equity is from 8.91 percent to 10.39 percent. My final recommendation is a 10.15 percent return for SWG's cost of equity capital.

Q How did you arrive at your recommended 10.15 percent cost of common equity?

A. My recommended 10.15 percent cost of common equity was arrived at by rounding up the 10.39 percent extreme upper end of the results obtained from of my cost of common equity analysis and then reducing that figure by 25 basis points. My recommended cost of equity is 124 basis points higher than the 8.91 percent result derived from my DCF analysis.

Q. Why have you chosen a return on equity that is 124 basis points higher than the results obtained in your DCF analysis and 25 basis points lower than the upper end of your range of cost of equity estimates?

A. Because SWG is more heavily leveraged and faces a higher level of financial risk (i.e. the risk of not being able to meet debt service obligations) than the LDC's included in my proxy, I believe that an appropriate rate of return for the Company lies somewhere near the 10.39 percent upper range of my cost of equity estimates. This upper range estimate is close to the 10.50 percent return on common equity that was adopted by the Nevada Public Utilities Commission during the Company's last rate case proceeding[11] in that state.

My decision to recommend a cost of common equity that is 25 basis points lower than the 10.39 percent high-end figure in my range of estimates was based on RUCO witness Marylee Diaz Cortez's recommendation that the Commission adopt RUCO's recommended rate design, which mitigates income volatility by shifting revenue recovery from SWG's commodity charge to the Company's fixed rate monthly minimum charge, in lieu of adopting the Company-proposed CMT. Ms. Diaz Cortez's recommended rate design recognizes SWG's concerns regarding the Company's ability to recover its revenue requirement if there is a decline in customer consumption. If the Commission adopts RUCO's recommended rate design, the Company will face a lower level of risk due to income volatility and therefore will not require a higher return on equity. Accordingly, I have reduced my high-end estimate by the same 25 basis points that the Company's cost of capital consultant, Mr. Hanley, is advocating in regard to his recommended cost of common equity as it relates to the CMT.

To a lesser degree, my decision to recommend a 10.15 percent cost of common equity, that is 124 basis points higher than the results I obtained

[11] Nevada Public Utilities Commission Docket No. 04-3011

from my DCF analysis, was based on SWG's inability to achieve higher levels of shareholder equity since the Company's last rate case proceeding, and my comparison of Value Line projections for the LDC's in my proxy against the Value Line projections for SWG. The combination of my upwardly adjusted DCF result and the use of a hypothetical capital structure, comprised of 53 percent debt, 5 percent preferred equity and 42 percent common equity, provides SWG with a higher weighted cost of equity.

Q. What percentage of debt and equity comprise SWG's actual capital structure?

A. The Company's actual capital structure during the Test Year was comprised of 61 percent debt, 5 percent preferred equity and 34 percent common equity. SWG's capital structure has a higher level of debt than the capital structures of the ten LDC's that I included in my DCF and CAPM proxies (Schedule WAR-9).

...

Q. What is the difference between your recommended weighted cost of capital, using your recommended 10.15 percent cost of common equity and your recommended hypothetical capital structure, and the weighted cost of capital that results from using your recommended 10.15 percent cost of common equity in the Company's actual capital structure?

A. The use of my 10.15 percent cost of common equity in my recommended hypothetical capital structure results in a weighted cost of capital of 8.64 percent. The use of my recommended cost of equity in SWG's actual capital structure results in a weighted cost of capital of 8.43 percent or a difference of 21 basis points.

Q. How does SWG's beta coefficient compare to the average beta coefficient that you used in your CAPM analysis?

A. SWG's beta coefficient is 0.75 as opposed to the average beta of 0.79 that I used in my CAPM analysis (Attachment C).

Q. What would the expected return on equity for SWG be if you substituted SWG's beta into your CAPM models using both a geometric and arithmetic mean?

A. Substituting a 0.75 beta into the models produces results that are identical to those obtained for four of the LDC's that I included in my proxy group (Cascade Natural Gas Corp., Laclede Group, Inc., Piedmont Natural Gas Company, and WGL Holdings, Inc.). As exhibited on pages 1 and 2 of schedule WAR-7, the expected return for those four LDCs is 8.56 percent, using a geometric mean, and 10.06 percent, using an arithmetic mean. My recommended cost of equity for SWG of 10.15 percent is 159 basis points higher than the low end (geometric mean) of the CAPM results that I have just described and 9 basis points higher than the high end (arithmetic mean).

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are investing in non-regulated entities also.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. Economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board ("Federal Reserve" or "Fed"), chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[12] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate

[12] The interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy over the last four years?

A. The U.S. economy entered into a recession around the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve Chairman was cutting rates in the hope of avoiding the recession that the U.S. is still in the process of recovering from.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates, moves which indicated that the worst may be over and that the current recession might have bottomed out during the last quarter of 2001, a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in 45 years.

Even though some signs of economic strength, that were mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC stated "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.'"[13]

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. Between June 29, 2004 and June 30, 2005, the FOMC has raised the federal funds rate eight more times to its current level of 3.25 percent (the next scheduled meeting of the FOMC will be on August 9,

[13] Wolk, Martin, "Fed leaves short-term rates unchanged," MSNBC, January 28, 2004.

2005). As expected, banks have followed the Fed's lead and have boosted the prime rate to its current level of 6.25 percent. According to an article that appeared in the September 22, 2004 edition of the The Wall Street Journal, the FOMC's decision to begin raising rates was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy[14]. In other words, the Fed is trying to head off inflation *before* it becomes a problem.

Since it began increasing the federal funds rate in June 2004, the Federal Reserve has stated that it would increase rates at a "measured" pace.

Many analysts and economists interpret this language to mean that Chairman Greenspan will be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates resulted in financial turmoil, which contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[15].

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[14] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

[15] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

Q. Putting this all into perspective, how have the Fed's actions over the past four years affected benchmark rates?

A. Virtually all of the benchmark rates have fallen to levels not seen in over forty-five years. The Fed's actions have had the overall effect of reducing the cost of many types of business and consumer loans. Despite the recent increases in the federal funds rate, the federal discount rate (the rate charged to member banks) has fallen from 5.73 percent in 2000, to its present level of 4.25 percent. Despite the recent increases, rates are still at historically low levels.

Q. What has been the trend in other leading interest rates over the last year?

A. As of July 15, 2005, all of the leading interest rates have edged up. The prime rate has increased from 4.25 percent a year ago to a current level of 6.25 percent. The benchmark federal funds rate, just discussed, has increased from 1.25 percent, in July 2004, to its current level of 3.25 percent (the result of the nine quarter point increases noted earlier). The yields on all maturities of U.S. Treasury instruments, with the exception of the 10-year, 30-year and 30-year zero coupon bonds, which have fallen 41, 90, and 109 basis points respectively since July 2004, have increased over the past year. This unusual situation, in which long-term rates are falling as short-term rates are rising, is creating a flat yield curve that has been described by Chairman Greenspan as a "conundrum."[16] The 91-day

[16] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005.

T-bill rate, used in my CAPM analysis, has increased from 1.26 percent, in July 2004, to 3.14 percent today. The 1-Year Treasury Constant Maturity rate has also increased from 2.00 percent over the past year to 3.55 percent today. Again, these levels are still low when they are compared with the historical yields displayed on Schedule WAR-8.

Q. How have economists and members of the investment community viewed the Fed's rate actions since June 2004?

A. The change in the Fed's language from "considerable period" to "patient" to "measured," that have been noted through the course of my testimony, has pretty much summed up the Fed's course of action during the economic recovery that is still in progress. In his October 2004 column for Wells Capital Management's ("Wells") Monthly Market Outlook publication, Senior Economist Gary E. Schlossberg viewed the Fed's recent credit tightening action as a trend that is likely to continue barring an unraveling of the economic recovery, a major disruption in the financial markets or a renewed threat of declining prices. According to Mr. Schlossberg, the Fed appears to be determined to engineer a fundamental shift from its past policy of "aggressive accommodation" to what he considers to be a more "neutral" policy stance (determined by both the rate of inflation and an additional "premium" of possibly 1.00 percent to 1.50 percent) via a series of rapid fire quarter-point increases that will result in a federal funds rate of 4.00 percent to 4.50 percent by the end of 2005. Mr. Schlossberg's expectation of future incremental increases in the federal funds rate was shared by Mickey Levy, Chief Economist for Bank of America, and by Value Line analysts. In the October 1, 2004 edition of Value Line's "Selection & Opinion" publication, Value Line's analysts stated that they believed that the Fed was following a prudent course. In their opinion the Fed's interest rate cutting helped to avoid a more serious recession and the Fed's present course of action will help to insure that the current upturn in the economy is sustained while keeping inflation low and under control at the same time. Although the increases in the federal funds rate have been viewed as a positive development (i.e. evidence of a strengthening economy), the upward movements in crude oil prices have not. Rising crude oil prices have become a serious concern to analysts and economists because of their potential adverse impact on corporate earnings.

Q. What is the current outlook for interest rates and the economy?

A. The views expressed by Messrs Levy and Schlossberg during the last quarter of 2004 appear to have been on target. A Reuters article[17], published on Sunday, July 17, 2005, quoted former Federal Reserve Governor Lyle Gramley as stating that, in an upcoming meeting with congressional leaders, Chairman Greenspan (who will retire from the Fed at the end of January, 2006) "...will give no indication at all that the Fed is

[17] Bull, Alister, "Greenspan, at end of era, to signal more rate rises," Reuters, July 17, 2005.

near the end of raising short-term interest rates". Mr. Gramley, who is now at the Washington-Stanford Research Group, went on to say "Quite the contrary. I think he will caution Congress on the need to continue raising interest rates". The article also quoted the presidents of the Richmond and San Francisco Federal Reserve Banks who believe that the FOMC will continue its present course of action. Goldman Sachs' chief U.S. economist Bill Dudley was quoted as saying that he is forecasting that the Fed Funds rate, as projected by Mr. Schlossberg, will hit the 4.5 percent figure next year.

According to analysts and economists at both Value Line and Wells, the overall outlook for economic growth, and the current low interest rate environment, appears to be good despite a moderate pace of GDP growth. In their most recent Selection & Opinion outlook published on Friday, July 15, 2005, Value Line analysts had little to add to the comments that appeared in the June 10, 2005 quarterly economic review, in which they stated the following:

> "This modest rate of GDP growth is unlikely to rekindle wide-spread inflationary pressures. To be sure, there has been a pickup in pricing in the energy area, where quotations for oil are close to a record high. On the whole, though, inflation continues to be held in check, with solid gains in productivity (or labor cost efficiency) being instrumental in helping maintain this relative pricing stability. Here as well, we think these benign trends will remain in place. Such moderation, plus the sluggish rate of employment growth, should dissuade the Federal Reserve from raising interest rates aggressively."

The following quote[18] by Wells' Chief Investment Strategist, James W. Paulsen, Ph.D., had this to say:

> "Most importantly, prior to every major economic slowdown or recession in the last 25 years, long-term bond yields rose significantly. This simply has not yet occurred in the contemporary cycle. Not only did long-term yields decline in the last recession to levels not seen in about four decades, they have yet to sustain any meaningful rise above these very low levels. Even the hikes of short-term interest rates by the Fed appear timid. Thus far they have been lifted little more than the rise in the core rate of consumer inflation, leaving the real Fed funds rate virtually unchanged. It may be that the Fed has been raising short-term yields, but the odd if not unique imperviousness of long-term yields to Fed action suggest interest rate policy has not been very (if at all) restrictive."

Q. How do Value Line's analysts view the impact of the Federal Reserve's interest rate actions on the natural gas (distribution) segment of the U.S. economy?

A. In his June 17, 2005 update on the natural gas (distribution) segment, Value Line analyst Evan I. Blatter, stated the following:

> The stocks in this industry offer income-oriented investors good stock price stability. With the volatility of the stock market in recent years, many investors have grown concerned over the value of their nest eggs. For conservative, income-oriented investors, many stocks in this industry have a lot to offer, not the least of which is a steady stream of income. Indeed, most of these shares offer above-average dividend yields compared to the rest of the stocks covered in the *Value Line Investment Survey*. Should interest rates continue to go up, however, other income-oriented investments may become more attractive and cause some downward pressure on the industry.

. . .

[18] Wells Capital Management's Economic and Market Perspective, April 2005, Pages 1.

Q. What are Value Line analyst's projections for return on common equity for the LDC's in your sample and the natural gas (distribution) segment as a whole?

A. For my sample group of LDC's, Value Line's analysts are projecting returns on common equity ("ROE") that range from 7.5 percent to 13.5 percent over the 2005 to 2010 time frame. Value Line's ROE projections for the industry as a whole range from 12.0 percent to 12.5 percent over the same period (Attachment A).

Q. Please summarize how the economic data just presented relates to SWG.

A. The current benign rate of inflation translates into stable and even possibly declining prices for goods and services, which in turn means that SWG can expect its present operating expenses to either remain stable or possibly decline in the coming years. Lower interest rates would also benefit SWG in regard to any short or long-term borrowing needs that the Company may have. Lower interest rates would further help to accelerate growth in new construction projects and home developments (which have been on an upward trend according to data presented in Value Line) in the Company's service territory, and may result in new revenue streams to SWG.

Q. After weighing the economic information that you've just discussed, do you believe that the 10.15 percent cost of equity capital that you have estimated is reasonable for SWG?

A. I believe that my recommended 10.15 percent cost of equity will provide SWG with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are still low by historical standards), continued growth in new housing construction (attributed to historically low interest rates), and the low and stable outlook for inflation are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my DCF and CAPM analyses have produced such a return. The results that I have obtained are consistent with Value Line's view that the LDC stocks included in my proxy "offer an above average dividend yield." In fact, my recommended 10.15 percent cost of common equity exceeds Value Line's return on common equity projections for SWG by 415 basis points during the 2005 time frame and by 15 basis points over the 2005 to 2010 time frame (Attachment C).

CAPITAL STRUCTURE

Q. Have you reviewed SWG's testimony regarding the Company's proposed capital structure?

A. Yes, I have.

Q. Please describe the Company's proposed capital structure.

A. The Company is proposing a hypothetical capital structure comprised of approximately 53 percent long-term debt, 5 percent preferred equity and 42 percent common equity.

Q. What capital structure are you proposing for SWG?

A. I have adopted the Company-proposed hypothetical capital structure.

Q. Is SWG's proposed hypothetical capital structure in line with industry averages?

A. Yes. As can be seen in Schedule WAR-9, the hypothetical capital structure being proposed by SWG is close to the average debt and equity percentages of my sample group of LDC's. The capital structures for those utilities averaged 51.2 percent for long-term debt, 0.3 percent for preferred equity, and 48.5 percent for common equity.

Q. Is SWG's actual capital structure in line with industry averages?

A. No. As discussed earlier, SWG's capital structure is heavier in debt than the capital structures of the other LDC's included in my cost of capital analysis (Schedule WAR-9).

Q. In terms of risk, how does SWG's capital structure compare to the LDC's in your sample?

A. The LDC's in my sample would be considered as having a lower level of financial risk (i.e. the risk associated with debt repayment) because of their lower levels of debt. The lower financial risk due to debt leverage is embedded in the cost of equities derived for those companies through the DCF analysis. Thus, the cost of equity derived from my DCF analysis is applicable to LDC's that are less leveraged and, theoretically speaking, not as risky as a utility with a level of debt similar to SWG's. In the case of a publicly traded company, such as those included in my proxy, a company with SWG's level of debt would be perceived as having a higher level of financial risk and would therefore also have a higher expected return on common equity.

Q. Have you made an upward adjustment to your DCF estimate based on this perception of higher financial risk?

A. Yes. As I also explained earlier, I have made an upward adjustment to my recommended cost of equity based on the results of my DCF and CAPM analyses.

...

Q. Have you accepted the Company-proposed 7.49 percent cost of long-term debt?

A. Yes I have. However, I do want to point out that the Company-proposed cost of long-term debt is somewhat overstated because the effective cost of two of the Company's debt issuances (i.e. the 7.5 % debenture, due on August 1, 2006, and the 8.0% debenture, due on August 1, 2026) were calculated on amounts that contain reacquisition costs related to SWG's purchase and sale of PriMerit Bank, an unregulated subsidiary that the Company sold sometime in the early 1990's.

Q. Why have you decided not to make an adjustment to the effective cost of these issues?

A. RUCO consultant Stephen G. Hill made light of this same issue during the Company's prior rate case proceeding in 2000. During that proceeding Mr. Hill pointed out that the effective cost of the two issues in question should be adjusted downward from 8.96 percent to 8.34 percent and 8.89 percent to 8.49 percent respectively, by cutting the reacquisition costs on these two issues in half (which would result in a 50/50 sharing of the costs between SWG and the Company's ratepayers). Mr. Hill eventually decided not to make such an adjustment since the Commission did not adopt his recommendation in a prior SWG rate case. I also have not made this adjustment, and have adopted the Company-proposed hypothetical capital structure and cost of debt of 7.49 percent

Q. Have you accepted the Company-proposed 8.20 percent cost of preferred equity?

A. Yes I have.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 11.95 percent cost of equity capital proposed by the Company's cost of capital witness, which assumes that the Commission will reject the Company-proposed CMT, is 180 basis points higher than the 10.15 percent cost of equity capital that I am recommending. The 11.70 percent cost of equity capital proposed by the Company's cost of capital witness, which assumes that the Commission will adopt the Company-proposed CMT, is 155 basis points higher than the 10.15 percent cost of equity capital that I am recommending.

Q. How does the Company's proposed weighted cost of capital compare with your recommended weighted cost of capital?

A. The Company has proposed a weighted cost of capital of 9.40 percent. This composite figure is the result of a weighted average of SWG's proposed 7.49 percent cost of long-term debt, 8.20 percent cost of preferred equity and the aforementioned 11.95 percent cost of equity capital (which assumes the Commission will reject the Company-proposed CMT). The Company-proposed 9.40 percent weighted cost of capital is

76 basis points higher than the 8.64 percent weighted cost that I am recommending.

COMMENTS ON SWG'S COST OF EQUITY CAPITAL TESTIMONY

Q. Please describe SWG's cost of equity capital testimony.

A. As noted earlier in my testimony, SWG's cost of capital testimony was prepared by the Company's cost of equity consultant Mr. Frank J. Hanley. Mr. Hanley's testimony presents the results of his cost of common equity analysis, which used the DCF, risk premium, CAPM, and comparable earnings methodologies. Mr. Hanley believes that the Company is entitled to an 11.95 percent cost of equity if the Commission rejects the Company-proposed CMT. Should the Commission approve the Company-proposed CMT, Mr. Hanley believes that an 11.70 percent cost of common equity is appropriate.

Q. Please compare the way you conducted your DCF analysis with the way that Mr. Hanley conducted his.

A. Mr. Hanley conducted a DCF analysis using the same single-stage constant growth model as I did. As I explained earlier in my testimony, Mr. Hanley also conducted his analysis using two separate proxy groups. His first proxy group included all of the LDC's that I included in mine plus Energen Corporation. His second proxy group is comprised of five LDC's and include the following: AGL Resources, Inc., Cascade Natural Gas

Corporation, Nicor Inc., Northwest Natural Gas Co., and Piedmont Natural Gas Company. In addition to the aforementioned proxy groups, Mr. Hanley also treated SWG as a stand-alone company in his analysis.

Q. How did Mr. Hanley determine the dividend yield component in his DCF model?

A. For the $\mathbf{P_0}$ portion of the DCF formula, Mr. Hanley averaged spot prices that occurred on October 1, 2004 with average high and low prices that occurred during the months of August 2004 and September 2004 to arrive at initial dividend yields of 4.18 percent for his proxy group of eleven LDC's and 4.34 percent for his group of five LDC's. His initial dividend yield results range from 3 to 19 basis points higher than the average 4.15 percent dividend yield that I obtained using an average of closing stock prices during a more recent an 8-week period. After obtaining the aforementioned initial dividend yields, Mr. Hanley then makes an upward adjustment, that is equal to fifty percent of the average projected five-year growth rate in earnings per share for each of the LDC's in his proxies, to arrive at his final dividend yields of 4.28 percent for his proxy group of eleven LDC's and 4.44 percent for his group of five LDC's. His final dividend yield estimate results range from 13 to 29 basis points higher than the average 4.15 percent dividend yield that I obtained using an average of closing stock prices during a more recent 8-week period.

Q. How did Mr. Hanley obtain his final growth or **g** estimate in his DCF analysis?

A. Mr. Hanley averaged the long-term (i.e. 2007-09) September 2004 *earnings per share projections* of Value Line analysts and the October 2004 five-year earnings per share projections of Thompson FN/First Call analysts to arrive at average DCF growth rates of 4.93 percent for his proxy group of eleven LDC's and 4.80 percent for his group of five LDC's. His final DCF growth estimate results range from 4 to 17 basis points higher than the average 4.76 percent dividend yield that I obtained.

Q. What is the average DCF result for the average dividend yields and growth estimates that were obtained by Mr. Hanley?

A. Mr. Hanley's average DCF costs of equity are 9.21 percent for his proxy group of eleven LDC's and 9.24 percent for his group of five LDC's. These results range from 30 to 33 basis points higher than my DCF cost of equity of 8.91 percent. However, Mr. Hanley's final DCF cost of equity estimates range from 10.36 percent for his proxy group of eleven LDC's and 10.20 percent for his group of five LDC's. Mr. Hanley's final DCF cost of equity estimate ranges from 129 to 217 basis points higher than the average 8.91 percent DCF cost of equity that I obtained. His stand-alone result for SWG is 10.69 percent.

Q. How did Mr. Hanley obtain his final DCF cost of equity estimates of 10.20 percent to 10.36 percent when his average results indicate a range of 9.21 percent to 9.24 percent?

A. To arrive at his final DCF cost estimates, Mr. Hanley ignored any results that were lower than 9.90 percent, which he states was the lowest rate awarded to a gas distribution utility between January 1, 2003 and June 4, 2004. This decision eliminated the results of seven of the LDC's in his proxy group of eleven and three of the LDC's in his proxy group of five and produces a higher DCF cost of equity estimate.

Q. Did you conduct a risk premium analysis?

A. No.

Q. Please compare the results of your CAPM analysis with the results of Mr. Hanley's CAPM analysis.

A. Mr. Hanley performed two CAPM analyses, one using the traditional CAPM model which I used (i.e. $k = r_f + [\, ß\, (r_m - r_f)]$) and a second using the empirical ("ECAPM") version of the model which assumes that the risk-free rate of return used in the traditional model is understated.

Q. Why didn't you use the ECAPM version in your CAPM analysis?

A. As I stated earlier in my testimony, the Value Line betas that I used in my CAPM model are adjusted by Value Line for their long-term tendency to converge toward 1.00. This eliminates the need to use the ECAPM version, which assumes that an upward adjustment is required for the risk-free rate of return.

Q. What were the differences between your CAPM analysis and Mr. Hanley's CAPM analysis?

A. Mr. Hanley performed his analysis using the same two proxies that he used in his DCF analyses and also treated SWG as a stand-alone entity. His CAPM analysis produced an average expected return, or **k,** of 11.08 percent for his group of eleven LDC's and 11.29 percent for his group of five LDC's. His results ranged from 69 to 90 basis points higher than my 10.39 percent CAPM analysis result using an arithmetic mean, and 226 to 247 basis points higher than my 8.82 percent CAPM analysis result using a geometric mean. His stand-alone result for SWG is 11.37 percent. Mr. Hanley's ECAPM analysis produced an average expected return of 11.41 percent for his group of eleven LDC's and 11.68 percent for his group of five LDC's. His results ranged from 102 to 129 basis points higher than my 10.39 percent CAPM analysis result using an arithmetic mean, and 259 to 286 basis points higher than my 8.82 percent CAPM analysis result using a geometric mean. His ECAPM result for SWG as a stand-alone entity is 11.73 percent. Again, in calculating his final average, Mr. Hanley ignored any expected returns that were 9.90 percent or lower.

Q. What beta coefficient (ß) did you use in your CAPM model and what beta coefficient did Mr. Hanley's use in his CAPM analysis?

A. I used a beta coefficient of 0.79, which is an average of Value Line's adjusted betas for the ten LDC's included in my proxy. Mr. Hanley used an average beta coefficient of 0.74 for his group of eleven LDC's and an average beta coefficient of 0.79 in his group of five LDC's. Mr. Hanley also used the adjusted betas published by Value Line at the time he performed both his CAPM and ECAPM his analyses. Technically, Mr. Hanley's ECAPM model overstates the expected return because of his use of an adjusted beta in a model that contains an upward adjustment for the risk-free rate of return.

Q. Please compare the risk free rate of return (r_f) proxies used in both your and Mr. Hanley CAPM analyses.

A. As I explained earlier in my testimony (page 25), I used a six-week average on a 91-day T-Bill rate. This resulted in a risk-free rate of return of 3.04 percent. Mr. Hanley on the other hand, used an average of economist's projections on the yields of 20-year U.S. Treasury bonds for the six quarters ending with the first calendar quarter of 2006. This resulted in a higher risk-free rate of return of 5.52 percent. The difference between the two average yields is 248 basis points.

Q. What is the difference between your market risk premium and the market risk premium used by Mr. Hanley?

A. Mr. Hanley derived his return on the market figure of 12.83 percent by averaging Value Line and Ibbotson Associates data. His risk premium of 7.31 percent was derived by subtracting his 5.52 percent risk free rate of return from his calculated 12.83 percent return on the market. The 7.31 percent market risk premium used by Mr. Hanley is 205 basis points lower than my 9.36 percent market risk premium, using an arithmetic mean, and is 5 basis points lower than my 7.36 percent market risk premium, using a geometric mean.

Q. Did you perform a comparable earnings analysis, which included non-regulated companies, similar to the one performed by Mr. Hanley?

A. No.

Q. How does Mr. Hanley arrive at his 11.95 percent cost of common equity figure after presenting the results of his DCF, risk premium, CAPM and comparable earnings analyses?

A. Mr. Hanley arrived at his recommended 11.95 percent cost of common equity by equally weighting the results of all four of his models. This resulted in average cost rates of 11.31 percent for his proxy group of eleven LDC's, 11.59 for his group of five LDC's and 11.85 percent for SWG as a stand-alone entity. After this he makes two further upward adjustments, one based on bond rating differences and the other to take into account SWG's lack of a weather normalization clause. These additional upward adjustments result in estimates of 11.87 percent for his group of eleven LDC's and 12.10 percent for his group of five LDC's. His final recommended cost of common equity of 11.95 percent is an average of the aforementioned estimates for the two proxy groups and the 11.85 percent cost for SWG. Mr. Hanley's 11.95 percent recommended cost of equity, assuming the Commission rejects the Company-proposed CMT, is 180 basis points higher than my recommended 10.15 percent return on common equity. His recommended cost of 11.70 percent equity, assuming the Commission adopts the Company-proposed CMT, is 155 basis points higher than my recommended 10.15 percent return on common equity.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Hanley constitute your acceptance of his positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on SWG?

A. Yes, it does.

Qualifications of William A. Rigsby

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Revenue Auditor II
Arizona Department of Revenue
Corporate Income Tax Audit Unit
Phoenix, Arizona
November 1993 – October 1994

Tax Examiner Technician I
Arizona Department of Revenue
Transaction Privilege Tax Audit Unit
Phoenix, Arizona
July 1991 – November 1993

Appendix 1

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Communications, Inc.	T-01051B-03-0454 et al.	Price Cap Plan
Chaparral City Water Company, Inc.	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Tucson Electric Power	E-01933A-04-0408	Rate Review

ATTACHMENT A

NATURAL GAS (DISTRIBUTION)

INDUSTRY TIMELINESS: 96 (of 98)

The Natural Gas Distribution Industry's Timeliness rank has fallen one notch since our last report in March: 96 (of 98). March-period earnings for most of the gas utilities we cover were down year over year as a result of milder temperatures across most of the United States. This will likely affect full-year earnings since most of these distribution companies' profits are derived during the winter quarters (March and December).

Regulated Utilities

The key features of gas-utility stocks are their safety and better-than-average dividend yields, *not* price performance or appreciation potential. Local distribution companies (LDCs) are natural gas utilities that are regulated by both individual state and/or federal regulatory agencies. They are considered natural monopolies since it is more cost-efficient to build one pipeline system to serve a region, versus multiple distributors competing over the same location. As a result of the government allowing each company to operate essentially as a monopoly, regulators set allowable rates of return that each company is able to earn. Should earnings be less than the permitted rate, the company is able to petition regulators for higher rates. This has been the case at *SEMCO*, which has received a $7 million-per-year increase in Michigan. *Southern Union* received a $22.5 million rate increase at its Missouri Gas Light Energy unit, and is petitioning for an additional increase. These increases will likely lead to higher profit levels at these companies. However, should distributors earn profits in excess of their allowable rates over an extended period, they may be subject to a regulatory review. If it is determined that they are in fact exceeding their permitted rates, they may be subject to a rate reduction.

Nonregulated Activities

The gas distribution industry has experienced some changes over the past decade. In 1992, The Federal Energy Regulatory Commission, instituted Order 636, which required pipeline operators to unbundle transportation and storage services, along with guaranteeing gas marketers access to their distribution networks. As a result, many distribution companies have entered into activities outside of their core distribution operations. These activities include retail-energy marketing, energy trading, and oil and gas exploration and production. *Piedmont Natural Gas*, for example, intends to grow its nonregulated segment to at least 15% of total earnings. In fact, most companies in this industry have some portion of their earnings coming from nonregulated operations, and are looking to boost their percentage of earnings from this segment in the coming years. Furthermore, as profits in nonregulated operations rise, regulatory agencies seem less likely to give out rate increases. This is the tradeoff they face, as nonregulated activities have no restrictions on their return on equity.

Natural gas prices

The higher natural gas prices of late have primarily benefited those companies that are involved in nonregulated activities. In fact, gas distributors are actually hurt by rising gas prices. They continue to earn their allowable return on equity, but the added costs of gas are passed onto customers. This can sometimes result in the loss of customers, additional conservation among customers, along with an increase in bad debt expense.

Conservative Investment

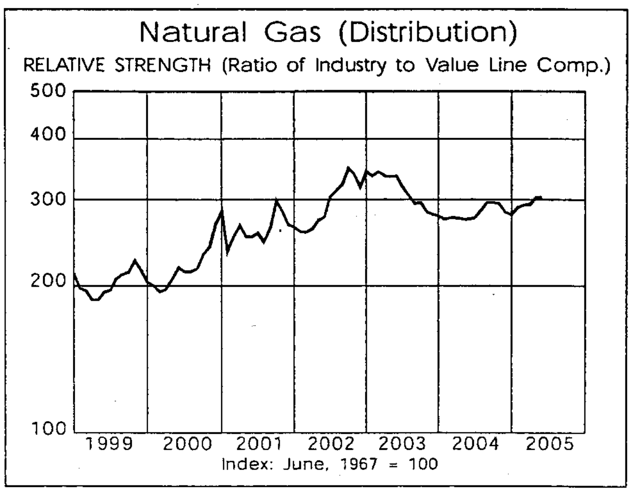
The stocks in this industry offer income-oriented investors good stock-price stability. With the volatility of the stock market in recent years, many investors have grown concerned over the value of their nest eggs. For conservative, income-oriented investors, many stocks in this industry have a lot to offer, not the least of which is a steady stream of income. Indeed, most of these shares offer above-average dividend yields compared to the rest of the stocks covered in *The Value Line Investment Survey*. Should interest rates continue to go up, however, other income-oriented investments may become more attractive and cause some downward pressure on the industry

Still, there is great deal of diversity in constituents of this industry. The biggest differences are usually seen with nonregulated business segments. As companies shift toward these businesses, they increase the potential for capital appreciation and risk of capital loss. Moreover, companies making a concerted push to nonregulated businesses may be less generous with dividend increases, preferring to use money to build new ventures rather than pay it out to shareholders. Investors should pay close attention to this factor when making commitments here.

Evan I. Blatter

Composite Statistics: Natural Gas (Distribution)

2001	2002	2003	2004	2005	2006		08-10
27611	22947	29981	33220	***35000***	***37950***	Revenues ($mill)	***42000***
1070.4	1231.5	1395.3	1735.9	***1750***	***1850***	Net Profit ($mill)	***2100***
39.7%	35.3%	37.4%	35.6%	***36.0%***	***36.0%***	Income Tax Rate	***36.0%***
3.9%	5.4%	4.7%	5.2%	***5.0%***	***4.9%***	Net Profit Margin	***5.0%***
57.4%	57.8%	55.9%	53.2%	***53.0%***	***53.0%***	Long-Term Debt Ratio	***52.5%***
41.5%	41.4%	43.7%	45.7%	***45.0%***	***45.0%***	Common Equity Ratio	***45.5%***
24342	24907	28436	31268	***33500***	***35400***	Total Capital ($mill)	***39450***
24444	25590	31732	32053	***33500***	***35000***	Net Plant ($mill)	***40000***
6.1%	6.6%	6.4%	7.1%	***7.0%***	***7.0%***	Return on Total Cap'l	***7.0%***
10.3%	11.7%	11.1%	11.9%	***12.0%***	***12.0%***	Return on Shr. Equity	***12.5%***
10.5%	11.8%	11.2%	12.0%	***12.0%***	***12.0%***	Return on Com Equity	***12.5%***
2.5%	3.9%	4.1%	5.5%	***5.5%***	***5.5%***	Retained to Com Eq	***5.5%***
76%	68%	64%	55%	***60%***	***60%***	All Div'ds to Net Prof	***60%***
16.8	14.8	14.1	13.6	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	***13.0***
.86	.81	.80	.72			Relative P/E Ratio	***.87***
4.5%	4.5%	4.5%	4.0%			Avg Ann'l Div'd Yield	***4.6%***
244%	280%	314%	308%	***315%***	***330%***	Fixed Charge Coverage	***375%***



ATTACHMENT B

AGL RESOURCES NYSE-ATG

RECENT PRICE **35.30** | P/E RATIO **15.3** (Trailing: 14.6 Median: 14.0) | RELATIVE P/E RATIO **0.84** | DIV'D YLD **3.5%** | VALUE LINE

TIMELINESS	3 Raised 2/4/05
SAFETY	2 New 7/27/90
TECHNICAL	3 Lowered 1/7/05
BETA .85 (1.00 = Market)	

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	19.4	20.0	22.0	21.6	23.4	23.4	23.2	24.5	25.0	29.3	33.7	36.3
Low:	14.6	14.9	17.1	17.8	17.7	15.6	15.5	19.0	17.3	21.9	26.5	32.0

Target Price Range 2008 | 2009 | 2010

2008-10 PROJECTIONS

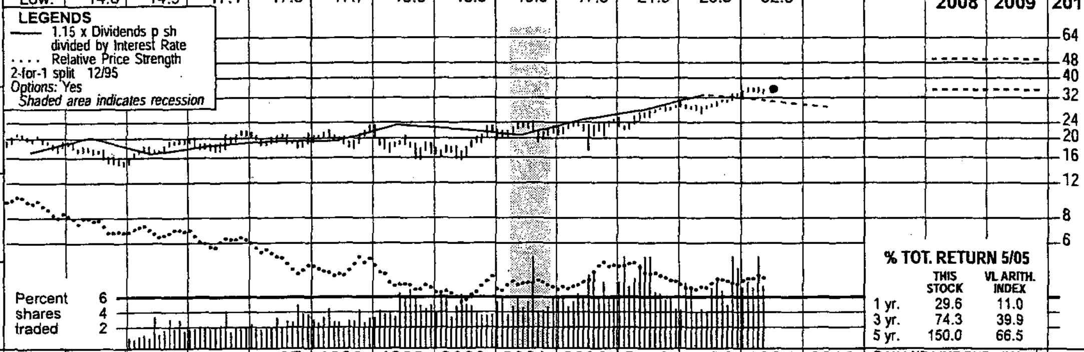
	Price	Gain	Ann'l Total Return
High	45	(+25%)	9%
Low	35	(Nil)	4%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	0	0	0
Options	0	4	2	2	3	2	2	2	0
to Sell	0	4	2	2	2	2	2	2	0

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	91	128	119
to Sell	53	50	69
Hld's(000)	36912	48181	48662



% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	29.6	11.0
3 yr.	74.3	39.9
5 yr.	150.0	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
21.63	22.58	20.26	20.43	22.73	23.59	19.32	21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	**31.10**	**32.25**	Revenues per sh A	**37.20**
1.93	2.04	2.07	2.31	2.25	2.24	2.33	2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	**3.95**	**4.10**	"Cash Flow" per sh	**4.60**
.95	1.01	1.04	1.13	1.08	1.17	1.33	1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	**2.30**	**2.40**	Earnings per sh A B	**2.75**
.94	.98	1.02	1.03	1.04	1.04	1.04	1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	**1.24**	**1.27**	Div'ds Decl'd per sh C■	**1.35**
2.65	2.73	2.95	2.74	2.49	2.37	2.17	2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	**3.30**	**2.75**	Cap'l Spending per sh	**2.25**
8.83	8.97	9.42	9.70	9.90	10.19	10.12	10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	**19.10**	**20.15**	Book Value per sh D	**23.90**
43.40	44.32	47.57	48.69	49.72	50.86	55.02	55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	**77.20**	**77.50**	Common Shs Outst'g E	**78.00**
13.7	14.2	15.3	15.5	17.9	15.1	12.6	13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**15.0**
1.04	1.05	.98	.94	1.06	.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.70	*estimates*		Relative P/E Ratio	**1.00**
7.2%	6.8%	6.4%	5.9%	5.4%	5.9%	6.2%	5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%			Avg Ann'l Div'd Yield	**3.2%**

CAPITAL STRUCTURE as of 3/31/05
Total Debt $1656.0 mill. Due in 5 Yrs $335.0 mill.
LT Debt $1618.0 mill. LT Interest $85.0 mill.

(Total interest coverage: 4.5x)
Leases, Uncapitalized Annual rentals $27.0 mill.

Pension Assets-12/04 $279.0 mill. Oblig. $340.0 mill.

Pfd Stock None
Common Stock 77,109,918 shs. as of 5/3/05

MARKET CAP: $2.7 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
1063.0	1220.2	1287.6	1338.6	1068.6	607.4	1049.3	868.9	983.7	1832.0	**2400**	**2500**	Revenues ($mill) A	**2900**
74.3	75.6	76.6	80.6	52.1	71.1	82.3	103.0	132.4	153.0	**180**	**185**	Net Profit ($mill)	**220**
36.9%	38.6%	37.9%	32.5%	33.1%	34.3%	40.7%	36.0%	35.9%	37.0%	**38.0%**	**38.5%**	Income Tax Rate	**38.5%**
7.0%	6.2%	5.9%	6.0%	4.9%	11.7%	7.8%	11.9%	13.5%	8.4%	**7.5%**	**7.4%**	Net Profit Margin	**7.6%**
47.4%	46.2%	48.7%	47.5%	45.3%	45.9%	61.3%	58.3%	50.3%	54.0%	**52.0%**	**51.0%**	Long-Term Debt Ratio	**46.0%**
47.6%	48.9%	45.9%	47.1%	49.2%	48.3%	38.7%	41.7%	49.7%	46.0%	**48.0%**	**49.0%**	Common Equity Ratio	**54.0%**
1170.3	1201.3	1356.4	1388.4	1345.8	1286.2	1736.3	1704.3	1901.4	3008.0	**3090**	**3175**	Total Capital ($mill)	**3475**
1350.3	1415.4	1496.6	1534.0	1598.9	1637.5	2058.9	2194.2	2352.4	3178.0	**3300**	**3450**	Net Plant ($mill)	**3740**
8.2%	8.0%	7.3%	7.6%	5.7%	7.4%	6.5%	8.1%	8.9%	6.3%	**7.0%**	**7.5%**	Return on Total Cap'l	**7.5%**
12.1%	11.7%	11.0%	11.1%	7.1%	10.2%	12.3%	14.5%	14.0%	11.0%	**12.0%**	**12.0%**	Return on Shr. Equity	**11.5%**
12.5%	12.1%	11.3%	12.3%	7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	**12.0%**	**12.0%**	Return on Com Equity	**11.5%**
4.6%	3.8%	3.2%	4.4%	NMF	3.2%	4.2%	7.0%	6.6%	5.6%	**5.5%**	**5.5%**	Retained to Com Eq	**6.0%**
66%	71%	74%	64%	101%	72%	65%	52%	53%	49%	**54%**	**53%**	All Div'ds to Net Prof	**48%**

CURRENT POSITION ($MILL.)	2003	2004	3/31/05
Cash Assets	16.5	49.0	24.0
Other	730.8	1408.0	1155.0
Current Assets	747.3	1457.0	1179.0
Accts Payable	73.7	207.0	648.0
Debt Due	77.0	334.0	38.0
Other	903.7	936.0	528.0
Current Liab.	1054.4	1477.0	1214.0
Fix. Chg. Cov.	357%	510%	440%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	-2.0%	-3.5%	12.5%
"Cash Flow"	4.0%	6.5%	5.5%
Earnings	6.0%	11.0%	5.0%
Dividends	0.5%	0.5%	3.5%
Book Value	4.5%	6.0%	8.0%

Fiscal Year Begins	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Fiscal Year
2002	173.4	255.1	190.7	249.7	868.9
2003	352.5	186.6	166.3	278.3	983.7
2004	651.0	294.0	262.0	625.0	1832.0
2005	912.0	*385*	*370*	*733*	*2400*
2006	*955*	*400*	*385*	*760*	*2500*

Fiscal Year Begins	EARNINGS PER SHARE A B Mar.31	Jun.30	Sep.30	Dec.31	Full Fiscal Year
2002	.89	.21	.17	.55	1.82
2003	.98	.29	.27	.54	2.08
2004	1.00	.33	.31	.64	2.28
2005	1.14	*.31*	*.29*	*.56*	*2.30*
2006	*1.15*	*.33*	*.31*	*.61*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.27	.27	.27	.27	1.08
2002	.27	.27	.27	.27	1.08
2003	.27	.28	.28	.28	1.11
2004	.28	.29	.29	.29	1.15
2005	.31	.31			

BUSINESS: AGL Resources, Inc. is a public utility holding company. Its distribution subsidiaries are Atlanta Gas Light, Chattanooga Gas, and Virginia Natural Gas. The utilities have around 2.2 million customers in Georgia, primarily Atlanta, Virginia, and in southern Tennessee. Also engaged in nonregulated natural gas marketing and other, allied services. Also wholesales and retails propane. Nonregulated subsidiaries: Georgia Natural Gas Services markets natural gas at retail. Acquired Virginia Natural Gas, 10/00. Sold Utilipro, 3/01. Off./dir. own less than 1.0% of common stock (3/05 Proxy). President & CEO: Paula Rosput Reynolds. Incorporated: Georgia. Address: 10 Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

AGL Resources first-quarter earnings rose substantially. The March-period results were driven by additional earnings from NUI Corporation and Jefferson Island (about $38 million EBIT), both of which were acquired in the fourth quarter of 2004. These transactions were also responsible for most of the $10 million increase in AGL's interest expense, as the company assumed a substantial amount of debt from these purchases. Looking to the future, AGL has renewed a number of expiring Jefferson contracts with pacts that have staggered expiration dates over the 2006–2010 period. This should provide a fairly consistent revenue stream.

Regulatory matters at Atlanta Gas Light will play an important role in AGL's earnings outlook. The company had filed for a $26 million rate increase, but suffered an adverse ruling from the Georgia Public Service Commission. Its allowable return on equity was reduced from 11% to 10.375%, which is projected to reduce revenues by as much as $25 million. Even so, we are maintaining our earnings estimate of $2.30 a share for 2005, as the company has filed for, and received, a rehearing on the matter. This regulatory issue should be resolved quickly, but we may need to revisit our earnings estimates upon a final ruling.

Sequent Energy, a subsidiary of AGL is expanding. Daily sales have risen nearly 10% over the prior year, from 2.1 Bcf per day to 2.3 Bcf per day. The company would like to boost this volume to around 2.5 Bcf per day, partly by expanding its presence in the Midwest. Although this segment experienced year-over-year losses in the March quarter, that was due to accounting timing differences, which should adjust over time. We look for further expansion at Sequent, as well as AGL's other nonregulated units, which provided 4% of 2004's earnings.

This good-quality stock may appeal to conservative investors. The dividend yield is respectable at 3.5%, which is slightly below that of the average gas distribution stock. However, due to this stock's 35% run-up in price over the past 12 months, it currently offers below-average total-return potential over the pull to 2008–2010.

Evan I. Blatter *June 17, 2005*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses): '95, d$0.83; '99, $0.39; '00, $0.13; '01, $0.13; '03, d$0.07. Next earnings report due late July.
(C) Dividends historically paid early March, June, Sept, and Dec. ■ Div'd reinvest. plan available.
(D) Includes intangibles. In 2004: $354 million, $4.62/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	65

CASCADE NAT'L GAS NYSE-CGC

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
19.96	18.8 (Trailing: 21.5 / Median: 18.0)	1.03	4.8%

VALUE LINE

TIMELINESS **5** Lowered 11/26/04
SAFETY **3** New 7/27/90
TECHNICAL **3** Raised 5/13/05
BETA .75 (1.00 = Market)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	18.1	17.5	17.5	19.0	18.7	19.8	20.9	22.8	24.2	22.0	23.0	21.5
Low:	12.8	13.0	13.4	15.3	14.6	14.4	13.4	17.4	15.5	18.0	19.1	18.0

Target Price Range 2008 | 2009 | 2010

2008-10 PROJECTIONS

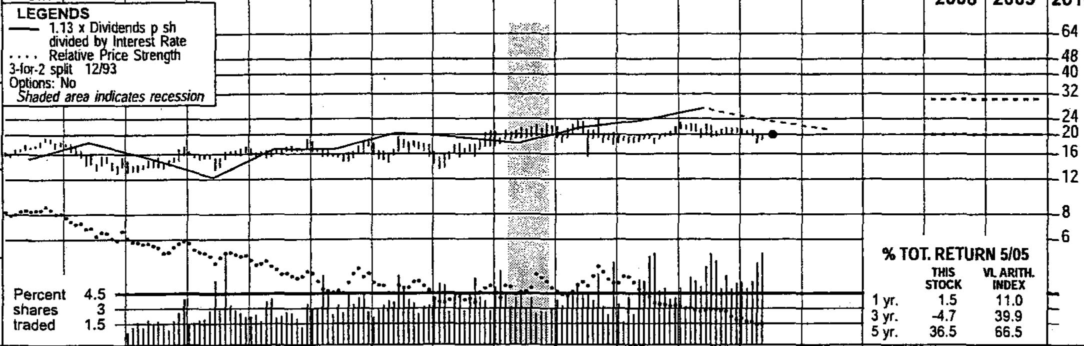
	Price	Gain	Ann'l Total Return
High	30	(+50%)	14%
Low	20	(Nil)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	1	0	0	1	1	0	1
Options	0	0	0	0	0	0	0	2	0
to Sell	0	0	0	0	0	0	0	1	0

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	44	33	37
to Sell	30	34	40
Hld's(000)	4631	4676	4743



% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.5	11.0
3 yr.	-4.7	39.9
5 yr.	36.5	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
26.87	24.45	23.27	20.03	21.88	21.59	19.98	11.84	17.85	17.17	18.89	21.90	30.40	29.06	27.20	28.23	*27.90*	*29.20*	Revenues per sh A	*40.00*
2.47	2.36	2.29	1.66	2.04	1.71	2.07	1.22	1.92	2.06	2.40	2.60	2.72	2.48	2.25	2.63	*2.50*	*3.00*	"Cash Flow" per sh	*4.60*
1.29	1.26	1.14	.63	1.05	.60	.80	.39	.93	.84	1.24	1.39	1.47	1.13	.87	1.19	*.95*	*1.25*	Earnings per sh AB	*1.60*
.85	.87	.90	.93	.94	.96	.96	.72	.96	.96	.96	.96	.96	.96	.96	.96	*.96*	*.96*	Div'ds Decl'd per sh C■	*.98*
1.99	2.50	2.97	4.64	3.85	3.06	4.12	2.42	2.66	2.32	1.81	1.65	2.16	1.91	2.56	3.50	*2.90*	*3.20*	Cap'l Spending per sh	*4.40*
7.96	8.33	8.63	9.09	9.96	9.81	9.76	10.09	10.16	10.07	10.36	10.79	11.01	10.34	10.11	10.52	*12.45*	*13.60*	Book Value per sh D	*15.30*
6.49	6.56	6.63	7.61	8.57	8.91	9.14	10.79	10.97	11.05	11.05	11.05	11.05	11.05	11.13	11.27	*11.30*	*11.30*	Common Shs Outst'g E	*12.00*
8.6	8.9	12.2	23.7	16.6	25.7	18.2	40.0	17.6	19.4	13.7	11.7	13.4	18.2	22.0	17.5	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.65	.66	.78	1.44	.98	1.69	1.22	2.51	1.01	1.01	.78	.76	.69	.99	1.25	.92	*Value Line*		Relative P/E Ratio	*1.05*
7.7%	7.8%	6.4%	6.2%	5.4%	6.2%	6.6%	4.6%	5.9%	5.9%	5.7%	5.9%	4.9%	4.7%	5.0%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
182.7	127.7	195.8	189.7	208.6	241.9	335.8	321.0	302.8	318.1	*315*	*330*	Revenues ($mill) A	*480*
7.7	4.2	10.6	9.8	14.2	15.4	16.2	12.5	9.7	13.3	*10.5*	*14.0*	Net Profit ($mill)	*20.0*
36.8%	34.8%	37.1%	37.4%	36.5%	37.1%	35.0%	34.9%	34.2%	36.2%	*36.5%*	*36.5%*	Income Tax Rate	*36.5%*
4.2%	3.3%	5.4%	5.2%	6.8%	6.4%	4.8%	3.9%	3.2%	4.2%	*3.3%*	*4.2%*	Net Profit Margin	*4.2%*
51.4%	46.8%	50.6%	48.4%	50.9%	51.2%	50.7%	59.1%	55.9%	52.1%	*53.0%*	*52.0%*	Long-Term Debt Ratio	*51.0%*
45.0%	50.0%	46.5%	48.7%	46.6%	48.8%	49.3%	40.9%	44.1%	47.9%	*47.0%*	*48.0%*	Common Equity Ratio	*49.0%*
198.5	217.8	239.4	228.5	245.6	244.2	246.6	279.1	255.5	247.4	*300*	*320*	Total Capital ($mill)	*375*
239.1	255.7	265.2	276.6	282.3	284.8	294.2	299.6	312.3	334.6	*350*	*375*	Net Plant ($mill)	*475*
5.9%	3.4%	6.2%	6.1%	7.5%	8.1%	8.5%	6.4%	6.0%	7.7%	*5.5%*	*6.0%*	Return on Total Cap'l	*7.0%*
8.0%	3.6%	9.0%	8.3%	11.7%	12.9%	13.3%	10.9%	8.6%	11.2%	*7.5%*	*9.0%*	Return on Shr. Equity	*11.0%*
8.1%	3.5%	9.1%	8.3%	12.0%	12.9%	13.3%	10.9%	8.6%	11.2%	*7.5%*	*9.0%*	Return on Com Equity	*11.0%*
NMF	NMF	.7%	NMF	2.7%	4.0%	4.6%	1.7%	NMF	2.1%	*NMF*	*2.0%*	Retained to Com Eq	*4.5%*
106%	NMF	93%	108%	78%	69%	65%	85%	110%	81%	*103%*	*77%*	All Div'ds to Net Prof	*59%*

CAPITAL STRUCTURE as of 3/31/05

Total Debt $177.4 mill. **Due in 5 Yrs** $55.0 mill.
LT Debt $158.9 mill. **LT Interest** $10.0 mill.
(LT interest earned: 2.8x; total interest coverage: 2.7x)

Pension Assets-9/04 $51.3 mill. **Oblig.** $65.5 mill.

Pfd Stock None

Common Stock 11,359,612 shs.
as of 4/29/05
MARKET CAP: $225 million (Small Cap)

CURRENT POSITION A ($MILL.)	2003	2004	3/31/05
Cash Assets	7.5	.5	6.1
Other	33.1	65.9	87.1
Current Assets	40.6	66.4	93.2
Accts Payable	10.5	12.9	22.9
Debt Due	25.8	47.5	18.5
Other	19.7	38.6	51.6
Current Liab.	56.0	99.0	93.0
Fix. Chg. Cov.	213%	269%	260%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	3.0%	9.5%	*6.0%*
"Cash Flow"	3.0%	3.0%	*11.0%*
Earnings	3.5%	1.0%	*7.0%*
Dividends	--	--	*.5%*
Book Value	.5%	--	*7.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	102.8	122.3	56.8	39.1	321.0
2003	100.5	109.3	53.8	39.2	302.8
2004	104.9	119.4	52.1	41.7	318.1
2005	104.6	117.7	*52.0*	*40.7*	*315*
2006	*105*	*125*	*55.0*	*45.0*	*330*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	.56	.86	d.06	d.23	1.13
2003	.60	.67	d.18	d.22	.87
2004	.72	.79	d.05	d.26	1.19
2005	.59	.65	*d.06*	*d.23*	*.95*
2006	*.70*	*.80*	*d.07*	*d.18*	*1.25*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.24	.24	.24	.24	.96
2002	.24	.24	.24	.24	.96
2003	.24	.24	.24	.24	.96
2004	.24	.24	.24	.24	.96
2005	.24	.24			

BUSINESS: Cascade Natural Gas Corporation distributes natural gas to around 225,000 customers in Washington and Oregon. In 2004, total throughput was 113.4 billion cu. ft. Core customers: residential, commercial, firm industrial, interruptible (69% of oper. margin, 23% of gas deliveries); non-core: industrial, transportation service (31%, 77%). Serves pulp & paper, plywood, chem. fertilizers, oil refining, & food process. inds. Main connecting pipeline: Northwest Pipeline Corp. '04 deprec. rate: 6.5%. Est'd plant age: 12 yrs. Has around 430 employees. Officers and directors own 1.7% of com. (12/04 proxy). President and Chief Executive Officer: David W. Stevens. Inc.: WA. Address: 222 Fairview Ave. North, Seattle, WA 98109. Tel.: 206-624-3900. Internet: www.cngc.com.

Cascade Natural Gas' earnings per share in fiscal 2005 (ends September 30th) are running substantially behind last year's. Demand from residential and commercial customers is being constrained by warmer temperatures and the effect of conservation efforts spurred by higher natural gas prices. To make matters worse, revenues from the gas management services unit are on the decline, reflecting the loss of some customers to energy marketers (a segment that has re-emerged in the wake of the Enron debacle). But the company's results are benefiting from expansion in the customer base and cost-containment initiatives. Nonetheless, it appears that the aforementioned negative factors will cause share net to plunge roughly 20%, to $0.95, in fiscal 2005. The bottom line stands to bounce back next year, though, assuming, of course, that operating margins recover. That would improve dividend coverage.

The company looks positioned to post decent results out to the end of this decade. Thanks to a generally favorable economic environment, the current pace of new home and commercial construction across Washington and Oregon is steady (resulting in healthy growth in Cascade's annual account hookups). We believe that these positive trends will continue. Moreover, good potential exists for new customers to be gained via conversions to natural gas from electricity or other fuel sources, given natural gas' environmental advantages and assuming that future prices moderate a bit from current levels. Too, management is considering a rate mechanism that would reduce earnings sensitivity to fluctuations in temperatures. (Regulators must approve the measure, however.) Finally, future earnings ought to be helped nicely by a project aimed at diminishing the need for meter readers to manually access customer properties. That said, the bottom line may advance between 8% and 10% annually over the 2008-2010 timeframe.

The stock of Cascade, though untimely, offers an appealing dividend yield. But additional hikes in the payout will likely be slow in coming, as cash flows are used to accommodate the company's expanding customer base.

Frederick L. Harris, III *June 17, 2005*

(A) Cal. yr. thru. 12/95. Changed to 9/30 fiscal yr. in '96. (B) Primary egs. thru. '97, then diluted. Excl. nonrec. gains (losses): '91, 19¢; '93, 3¢; '96, (11¢); '98, (2¢); '99, (1¢); '01, 9¢; '02, (16¢); '03, (5¢). '04 egs. don't add to total due to rounding. Next egs. rpt. due late July. (C) Dividends historically paid in the middle of Feb., May, Aug., Nov. ■Div'd reinvest. plan avail. (D) Incl. deferred charges. In '04: $21.4 mill., $1.90/sh. (E) In mill., adj. for stk. split.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	50
Earnings Predictability	70

KEYSPAN CORP. NYSE-KSE

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
39.72	16.6 (Trailing: 10.7, Median: 14.0)	0.90	4.7%

VALUE LINE

TIMELINESS **4** Lowered 12/10/04

SAFETY **2** Lowered 3/26/99

TECHNICAL **4** Lowered 5/6/05

BETA .80 (1.00 = Market)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	28.6	29.6	32.6	37.1	37.6	31.3	43.6	41.9	38.2	38.1	41.5	40.9
Low:	21.5	22.0	24.9	26.1	25.4	22.5	20.2	29.1	27.4	31.0	33.9	36.8

Target Price Range 2008 | 2009 | 2010

2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	10%
Low	40	(Nil)	5%

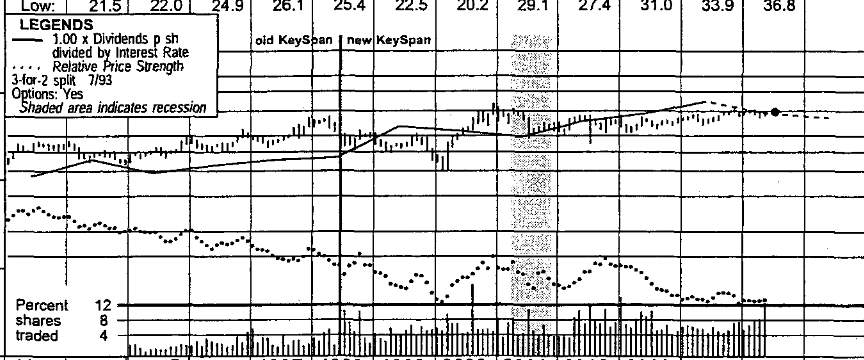
Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	4
to Sell	0	0	0	0	0	0	0	0	4

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	135	149	138
to Sell	133	120	135
Hld's(000)	78174	79838	81446

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 7/93
Options: Yes
Shaded area indicates recession



80
60
50
40
30
25
20
15
10
7.5

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	17.7	11.0
3 yr.	21.9	39.9
5 yr.	61.6	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
26.71	26.64	23.43	24.74	25.99	28.13	24.93	28.72	29.12	13.20	22.07	37.56	47.57	41.92	43.31	41.35	*40.75*	*43.25*	Revenues per sh	*54.25*
2.64	2.62	2.38	3.03	3.04	3.29	3.35	3.54	4.27	.45	3.57	4.51	5.72	6.36	6.22	7.22	*5.00*	*5.30*	"Cash Flow" per sh	*6.50*
1.68	1.62	1.45	1.35	1.73	1.85	1.90	1.96	2.12	d1.34	1.62	2.10	1.72	2.75	2.62	3.78	*2.40*	*2.60*	Earnings per sh B	*3.25*
1.19	1.23	1.27	1.29	1.32	1.35	1.39	1.42	1.46	1.50	1.78	1.78	1.78	1.78	1.78	1.79	*1.83*	*1.85*	Div'ds Decl'd per sh C ■	*2.00*
4.30	3.51	3.44	3.95	4.37	4.15	4.36	6.04	5.60	5.19	5.42	4.64	7.60	7.96	6.34	4.89	*5.40*	*5.50*	Cap'l Spending per sh	*7.00*
13.36	13.68	14.37	14.55	15.54	16.27	16.94	18.17	19.09	23.18	20.28	20.65	20.73	20.67	22.94	24.22	*26.75*	*27.65*	Book Value per sh D	*30.25*
36.29	37.30	42.28	43.45	46.38	47.59	48.79	49.86	50.77	130.42	133.87	136.36	139.43	142.42	159.66	160.82	*170.00*	*170.00*	Common Shs Outst'g E	*166.00*
10.1	11.9	13.1	15.1	14.3	13.7	12.7	13.7	13.8	--	16.8	14.8	20.8	12.7	13.1	9.90	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.76	.88	.84	.92	.84	.90	.85	.86	.80	--	.96	.96	1.07	.69	.75	.53	*Value Line*		Relative P/E Ratio	*.90*
7.0%	6.4%	6.7%	6.4%	5.3%	5.3%	5.8%	5.3%	5.0%	4.8%	6.5%	5.7%	5.0%	5.1%	5.2%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*4.7%*

CAPITAL STRUCTURE as of 12/31/04
Total Debt $5.35 bill. **Due in 5 Yrs** $2.5 bill.
LT Debt $4.42 bill. **LT Interest** $330.0 mill.
(total interest coverage: 3.8x)

Pension Assets-12/04 $1.9 bill. **Oblig.** $2.3 bill.

Pfd Stock $19.7 mill. **Pfd Div'd** $1.4 mill.

Common Stock 160,818,298 shs.

MARKET CAP: $6.4 billion (Large Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
1216.3	1432.0	1478.2	1721.9	2954.6	5121.5	6633.1	5970.7	6915.2	6650.5	*6925*	*7325*	Revenues ($mill) A	*9000*
91.8	97.2	106.1	d166.9	258.6	300.8	243.7	397.4	424.2	614.7	*415*	*450*	Net Profit ($mill)	*535*
32.0%	28.9%	35.0%	--	34.5%	41.8%	46.4%	36.2%	39.5%	34.6%	*38.0%*	*38.0%*	Income Tax Rate	*39.0%*
7.6%	6.8%	7.2%	NMF	8.8%	5.9%	3.7%	6.7%	6.1%	9.2%	*6.0%*	*6.1%*	Net Profit Margin	*5.9%*
46.4%	43.8%	43.5%	31.8%	37.5%	59.6%	61.2%	63.3%	60.0%	53.0%	*48.0%*	*48.0%*	Long-Term Debt Ratio	*49.5%*
53.2%	55.8%	56.5%	59.4%	60.6%	39.2%	37.7%	35.7%	39.1%	46.7%	*51.5%*	*51.5%*	Common Equity Ratio	*50.0%*
1553.8	1624.4	1714.1	5089.9	4482.1	7175.0	7672.3	8252.5	9356.9	8333.1	*8850*	*9100*	Total Capital ($mill)	*10050*
1512.6	1698.1	1810.6	3778.3	4240.0	6358.3	6605.9	7217.6	8894.3	7067.9	*7300*	*7700*	Net Plant ($mill)	*9000*
7.5%	7.4%	7.3%	NMF	7.1%	5.3%	4.5%	6.2%	5.8%	9.1%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
11.0%	10.7%	10.9%	NMF	9.2%	10.4%	8.2%	13.1%	11.3%	15.7%	*9.0%*	*9.5%*	Return on Shr. Equity	*10.5%*
11.1%	10.7%	10.9%	NMF	8.2%	10.0%	8.2%	13.3%	11.4%	15.6%	*9.0%*	*9.5%*	Return on Com Equity	*10.5%*
2.9%	2.9%	3.3%	NMF	NMF	1.4%	NMF	4.8%	3.9%	8.3%	*2.5%*	*3.0%*	Retained to Com Eq	*4.0%*
74%	73%	70%	NMF	110%	86%	103%	65%	66%	47%	*75%*	*71%*	All Div'ds to Net Prof	*64%*

CURRENT POSITION ($MILL.)	2002	2003	12/31/04
Cash Assets	170.6	205.8	922.0
Other	2045.9	2181.1	2156.6
Current Assets	2216.5	2386.9	3078.6
Accts Payable	1061.6	1141.6	906.7
Debt Due	927.1	483.4	928.3
Other	231.5	223.8	447.3
Current Liab.	2220.2	1848.8	2282.3
Fix. Chg. Cov.	289%	315%	257%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	6.0%	13.5%	*3.0%*
"Cash Flow"	8.0%	17.0%	*-0.5%*
Earnings	4.5%	21.0%	*1.0%*
Dividends	3.0%	4.0%	*2.0%*
Book Value	4.0%	1.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1871.6	1216.1	1079.8	1803.2	5970.7
2003	2512.5	1408.2	1131.8	1862.7	6915.2
2004	2595.6	1365.8	1050.4	1638.7	6650.5
2005	2480.5	*1400*	*1050*	*1994.5*	*6925*
2006	*2650*	*1425*	*1150*	*2100*	*7325*

Cal-endar	EARNINGS PER SHARE A B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1.51	.20	.02	1.02	2.75
2003	1.53	d.05	.07	1.07	2.62
2004	1.53	.28	d.73	1.63	2.71
2005	1.45	*.10*	*Nil*	*.85*	*2.40*
2006	*1.30*	*.05*	*Nil*	*1.25*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID A C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.445	.445	.445	.445	1.78
2002	.445	.445	.445	.445	1.78
2003	.445	.445	.445	.445	1.78
2004	.445	.445	.445	.445	1.78
2005	.455	.455			

BUSINESS: KeySpan Corp. is a holding company created 5/98, via the merger of KeySpan Energy (formerly Brooklyn Union) and Long Island Lighting. Acq. Eastern Enterprises 11/00, making KeySpan the largest gas distributor in the Northeast, serving most of New York City and nearby Long Island, and New England. Has 2.5 mill. gas meters in one-family homes and apartments. Also generates electricity and operates transmission/distr. sys. by contract with L.I. Power Author. Parent sold its 23.5% stake in Houston Explor. 11/24/04; Owns 20% of Iroquois Pipeline. Non-regulated subs. market gas supplies, sell ind'l energy mgmt. svcs. Has 9,950 empls. Chrmn.: R.B. Catell. Inc.: NY. Address: 1 MetroTech Center, Brooklyn, NY 11201. Tel.: 718-403-1000. Web:www.keyspanenergy.com.

KeySpan is giving itself a quality makeover. Since 1998, when Brooklyn Union Gas and Long Island Lighting merged to form KeySpan Corp., the new-parent set out to bring more kindred businesses into the fold. Early on, it acquired a major New England gas utility, making KeySpan the Northeast's largest regulated gas distributor. Other big investments included new power generation facilities, a majority stake in a Texas gas producer, and the purchase of several mechanical contractors doing energy-related services. But the effort of buying into new markets encountered some damaging financial pitfalls. Too, given its spreading base of nonregulated assets, KeySpan had overleveraged itself with senior capital, leaving a thin margin of safety for the dividend. Last year, though, management carried out a remedial plan, taking leave of shareholder-risk ventures. The outcome: a more comfortable financial profile, which allowed KeySpan to increase the dividend for the first time since the new company was formed.

While not a performance stock, KeySpan seems to be a secure holding for income. The recent conversion of $460 million of debt into common dilutes share earnings a little, but it leaves KeySpan with a balance sheet that's appropriately leveraged for a largely regulated, capital-intensive company. Though regulation leaves little latitude for widening the return on equity, revenues and profits from gas distribution and power generation should grow with the Northeast regional economy, with construction activity helping to expand the customer base. KeySpan trades at a moderate yield premium relative to other good-quality gas-utility stocks. The premium suggests investor doubt that the dividend has room to grow. Our take, at the moment, is that the yearly payout will grow slowly, but fast enough to encourage a little more support for this issue. In terms of business risks, KeySpan, through 2008-2010, is apt to encounter traditional hazards. They include fluctuating electricity prices and regulatory lag in an inflationary economy. KeySpan's recent issuance of $307 million of 30-year notes at 5.8% should help a little to ease the effect of lengthy oversight reviews.

Gerald Holtzman *June 17, 2005*

(A) Data for former KeySpan Energy through '97 (years end 9/30); new KeySpan Corp. from '98 on a calendar-year basis.(B) Diluted shs. Excl. nonrecur. gains (charges): '90, ($0.19); '96, $0.52; '97, $0.16; '03, ($0.23); '04, $0.53. Excl. gain (loss) discont. ops.: '00, ($0.02); '01, ($0.14); '02, ($0.14); '03, $0.01; '04, $0.94. Next egs. report due late July. (C) Dividends historically paid in February, May, August, and November. ■ Div'd reinvestment plan available. (D) Includes deferred charges. At 12/31/04: $18.31 /sh. (E) In millions, adjusted for split.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	50
Earnings Predictability	20

LACLEDE GROUP NYSE-LG

RECENT PRICE **30.05** | P/E RATIO **16.6** (Trailing: 17.1; Median: 15.0) | RELATIVE P/E RATIO **0.91** | DIV'D YLD **4.6%** | VALUE LINE

TIMELINESS 5 Lowered 11/5/04
SAFETY 2 Raised 6/20/03
TECHNICAL 4 Lowered 5/27/05
BETA .75 (1.00 = Market)

High:	25.6	23.1	24.9	28.6	27.9	27.0	24.8	25.5	25.0	30.0	32.5	32.8
Low:	18.3	18.4	20.0	20.3	22.4	20.0	17.5	21.3	19.0	21.8	26.0	26.9

Target Price Range

2008	2009	2010

2008-10 PROJECTIONS

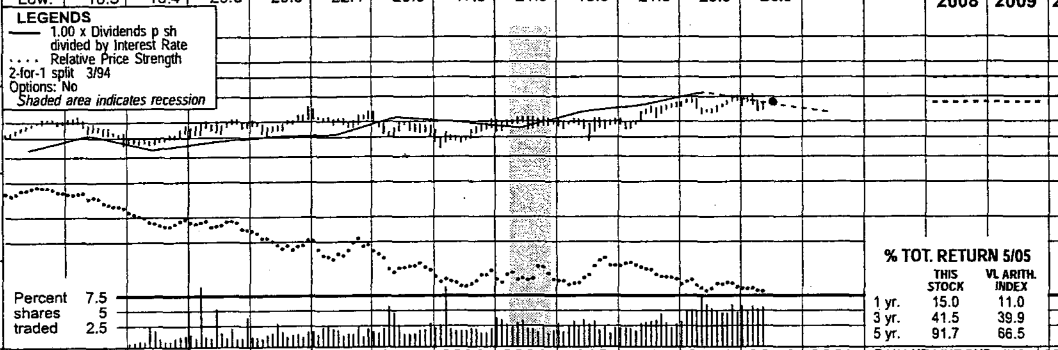
	Price	Gain	Ann'l Total Return
High	40	(+35%)	11%
Low	30	(Nil)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	0	0	3	1
to Sell	0	0	0	0	1	0	0	3	1

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	52	45	54
to Sell	35	40	38
Hld's(000)	6476	6396	6440



% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	15.0	11.0
3 yr.	41.5	39.9
5 yr.	91.7	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
31.57	30.21	28.10	26.83	32.33	33.43	24.79	31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	*70.70*	*77.65*	Revenues per sh	*103.70*
2.47	2.13	2.37	2.32	2.81	2.65	2.55	3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	*2.90*	*3.25*	"Cash Flow" per sh	*4.20*
1.45	1.08	1.28	1.17	1.61	1.42	1.27	1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	*1.75*	*1.95*	Earnings per sh A B	*2.25*
1.15	1.18	1.20	1.20	1.22	1.22	1.24	1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	*1.37*	*1.38*	Div'ds Decl'd per sh C■	*1.42*
1.82	1.87	2.46	2.87	2.62	2.50	2.63	2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	*2.60*	*2.70*	Cap'l Spending per sh	*3.00*
11.74	11.75	11.83	11.79	12.19	12.44	13.05	13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	*19.60*	*22.35*	Book Value per sh D	*29.65*
15.59	15.59	15.59	15.59	15.59	15.67	17.42	17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	*21.50*	*21.50*	Common Shs Outst'g E	*21.50*
10.3	14.6	12.5	15.8	13.5	16.4	15.5	11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.78	1.08	.80	.96	.80	1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.82	*Value Line*		Relative P/E Ratio	*1.05*
7.7%	7.5%	7.5%	6.5%	5.6%	5.3%	6.3%	5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*

CAPITAL STRUCTURE as of 3/31/05
Total Debt $466.7 mill. **Due in 5 Yrs** $175.0 mill.
LT Debt $380.4 mill. **LT Interest** $25.0 mill.
(Total interest coverage: 2.9x)

Leases, Uncapitalized Annual rentals $1.6 mill.
Pension Assets-9/04 $259.5 mill.
Oblig. $252.6 mill.
Pfd Stock $1.1 mill. **Pfd Div'd** $.06 mill.
Common Stock 21,113,155 shs.
as of 4/29/05

MARKET CAP: $625 million (Small Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
431.9	544.8	602.8	547.2	491.6	566.1	1002.1	755.2	1050.3	1250.3	*1520*	*1670*	Revenues ($mill) A	*2230*
20.9	32.8	32.5	27.9	26.9	26.0	30.5	22.4	34.6	36.1	*37.5*	*42.0*	Net Profit ($mill)	*50.0*
32.1%	35.9%	36.1%	35.6%	35.5%	35.2%	32.7%	35.4%	35.0%	34.8%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
4.8%	6.0%	5.4%	5.1%	5.5%	4.6%	3.0%	3.0%	3.3%	2.9%	*2.5%*	*2.5%*	Net Profit Margin	*2.2%*
40.2%	42.5%	38.0%	40.9%	41.8%	45.2%	49.5%	47.5%	50.4%	51.6%	*51.0%*	*51.0%*	Long-Term Debt Ratio	*51.0%*
59.3%	57.1%	61.6%	58.6%	57.8%	54.5%	50.2%	52.3%	49.4%	48.3%	*49.0%*	*49.0%*	Common Equity Ratio	*49.0%*
383.5	422.2	406.8	438.0	488.6	519.2	574.1	546.6	605.0	737.4	*860*	*980*	Total Capital ($mill)	*1300*
434.3	452.2	467.6	490.6	519.4	575.4	602.5	594.4	621.2	646.9	*680*	*705*	Net Plant ($mill)	*800*
7.1%	9.4%	9.7%	8.1%	7.1%	6.7%	6.9%	6.0%	7.4%	6.6%	*6.0%*	*6.0%*	Return on Total Cap'l	*5.5%*
9.1%	13.5%	12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.5%	10.1%	*9.0%*	*9.0%*	Return on Shr. Equity	*8.0%*
9.2%	13.6%	12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	*9.0%*	*9.0%*	Return on Com Equity	*8.0%*
.4%	4.5%	3.9%	1.8%	1.0%	.2%	1.8%	NMF	3.1%	2.7%	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
96%	67%	70%	83%	89%	98%	83%	113%	74%	73%	*78%*	*71%*	All Div'ds to Net Prof	*61%*

CURRENT POSITION ($MILL.)	2003	2004	3/31/05
Cash Assets	7.3	13.9	17.8
Other	280.6	323.7	366.2
Current Assets	287.9	337.6	384.0
Accts Payable	66.0	68.4	128.5
Debt Due	218.2	96.5	86.3
Other	82.1	97.7	89.8
Current Liab.	366.3	262.6	304.6
Fix. Chg. Cov.	295%	279%	280%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	5.0%	11.0%	*12.5%*
"Cash Flow"	1.0%	-1.0%	*7.0%*
Earnings	1.5%	-.5%	*6.0%*
Dividends	1.0%	.5%	*1.0%*
Book Value	2.5%	1.5%	*11.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	194.6	287.5	147.3	125.8	755.2
2003	280.1	422.2	186.6	161.4	1050.3
2004	332.6	475.0	245.1	197.6	1250.3
2005	442.5	576.5	*276*	*225*	*1520*
2006	*490*	*600*	*305*	*275*	*1670*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	.41	1.10	d.05	d.28	1.18
2003	.80	1.14	.11	d.21	1.82
2004	.87	1.12	.19	d.28	1.82
2005	.79	1.06	*.18*	*d.28*	*1.75*
2006	*.85*	*1.15*	*.20*	*d.25*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.335	.335	.335	.335	1.34
2002	.335	.335	.335	.335	1.34
2003	.335	.335	.335	.335	1.34
2004	.335	.34	.34	.34	1.36
2005	.34	.345			

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri (population, 2 million), including the city of St. Louis, St. Louis County, and parts of 8 other counties. Has more than 630,000 customers. Purchased SM&P for $43 million (1/02). Therms sold and transported in fiscal '04: 1.12 mill. Revenue mix for regulated operations: residential, 63%; commercial and industrial, 23%; transportation, 2%; other, 12%. Has around 3,440 employees. Officers and directors own approximately 6.0% of common shares (1/05 Proxy). Chairman, Chief Executive Officer, and President: *Douglas H. Yaeger. Incorporated:* Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.lacledegas.com.

In spite of higher revenues, Laclede Group's fiscal 2005 earnings per share have been lower than the year-ago figure. The shortfall partly reflects the dilutive impact of the sale of 1.7 million common shares in 2004. Moreover, Laclede Gas Company, the core unit, is suffering from the net effect of decreased gas volumes (due to unseasonably warm weather last November), plus a rise in operating costs (particularly natural gas and propane gas expense). On the positive side, the performance of Laclede Energy Resources is being boosted by increased margins and higher sales achieved in a favorable market. Also, losses for SM&P Utility Resources are narrowing, thanks to the return of a considerable portion of business from two customers and expansion into new and existing markets. Nevertheless, it appears that consolidated share net will decline moderately, to $1.75, in fiscal 2005. But the bottom line may snap back next year, assuming, of course, better demand and/or lower gas purchase costs.

We expect unexciting results for the company out to decade's end, given that Laclede Gas operates in a mature market. In fact, the customer base is expanding less than 1% annually, which means that internal growth for this operation will be modest, at best. As such, any substantial gains will have to come from the unregulated segments or from acquisitions, which we view as improbable. That said, annual share-net advances may only be in the mid-single-digit range over the 2008-2010 horizon.

Laclede Gas formed a long-term agreement with Cellnet Technology, under which the latter would install and operate an automated meter reading system. This move should eliminate the need for the utility, with nearly 40% of its meters indoors, to gain physical access to the customer properties (thus resulting in cost savings). The project is slated for completion in two years.

The good-quality stock offers an attractive dividend yield. But investors seeking significant growth in the payout are advised to look elsewhere, given that the gas distributor operates in a slow-growth environment. Meanwhile, the stock is ranked 5 (Lowest) for Timeliness.

Frederick L. Harris, III *June 17, 2005*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Next earnings report due late April.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Incl. deferred charges. In '04: $206.6 mill., $9.85/sh.
(E) In millions. Adjusted for stock split.
(F) Qtly. egs. may not sum due to change in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	65

NICOR, INC. NYSE-GAS

RECENT PRICE 39.67 | P/E RATIO 18.9 (Trailing: 17.7 Median: 14.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 4 Lowered 5/13/05

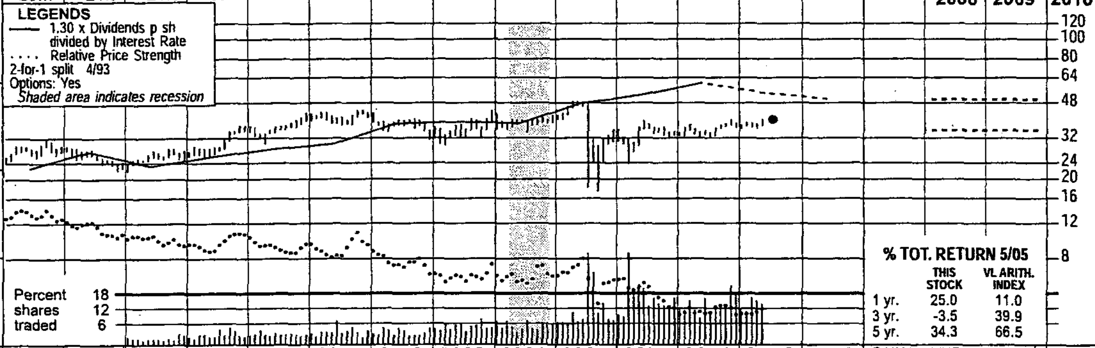
SAFETY 3 Lowered 6/17/05

TECHNICAL 4 Lowered 6/10/05

BETA 1.10 (1.00 = Market)

High:	29.3	28.5	37.1	42.9	44.4	42.9	43.9	42.4	49.0	39.3	39.7	40.6		
Low:	21.9	21.8	25.4	30.0	37.1	31.2	29.4	34.0	17.3	23.7	32.0	35.5		

Target Price Range 2008 | 2009 | 2010



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	10%
Low	35	(-10%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	1	0	0	1	0	0	1	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	86	109	96
to Sell	85	66	95
Hld's(000)	27339	27979	27493

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	25.0	11.0
3 yr.	-3.5	39.9
5 yr.	34.3	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
27.37	26.52	26.46	28.90	31.02	31.23	29.42	37.39	41.33	30.84	34.45	50.52	57.30	43.11	60.46	62.12	66.75	67.85	Revenues per sh	68.55
3.79	3.86	3.92	4.14	3.80	4.11	4.19	4.97	5.29	5.21	5.59	6.16	6.41	6.03	5.37	6.00	6.10	6.35	"Cash Flow" per sh	6.95
1.99	1.93	1.86	1.92	1.97	2.07	1.96	2.42	2.55	2.31	2.57	2.94	3.01	2.88	2.11	2.22	2.10	2.25	Earnings per sh A	2.55
1.00	1.06	1.12	1.18	1.22	1.25	1.28	1.32	1.40	1.48	1.54	1.66	1.76	1.84	1.86	1.86	1.86	1.86	Div'ds Decl'd per sh B ■	2.02
2.53	3.00	3.65	3.12	2.62	3.34	3.12	2.42	2.34	2.87	3.28	3.48	4.18	4.37	4.12	4.32	5.10	4.50	Cap'l Spending per sh	4.50
11.05	11.67	12.28	12.76	13.05	13.26	13.67	14.74	15.43	15.97	16.80	15.56	16.39	16.55	17.13	16.99	17.30	17.75	Book Value per sh	19.10
59.24	57.93	57.30	55.77	53.96	51.54	50.30	49.49	48.22	47.51	46.89	45.49	44.40	44.01	44.04	44.10	44.20	44.20	Common Shs Outst'g C	44.50
9.2	10.7	11.5	11.6	14.1	12.5	13.1	12.5	14.2	17.6	14.6	11.9	12.8	13.1	15.8	15.9	Bold figures are		Avg Ann'l P/E Ratio	16.0
.70	.79	.73	.70	.83	.82	.88	.78	.82	.92	.83	.77	.66	.72	.90	.85	Value Line		Relative P/E Ratio	1.05
5.5%	5.1%	5.2%	5.3%	4.4%	4.8%	5.0%	4.4%	3.9%	3.6%	4.1%	4.7%	4.6%	4.9%	5.6%	5.3%	estimates		Avg Ann'l Div'd Yield	5.1%
						1480.1	1850.7	1992.6	1465.1	1615.2	2298.1	2544.1	1897.4	2662.7	2739.7	2950	3000	Revenues ($mill)	3050
						99.8	121.2	124.3	111.1	121.9	136.4	136.3	128.0	93.1	98.1	95.0	100	Net Profit ($mill)	115
						35.3%	35.8%	35.0%	34.4%	34.7%	34.8%	33.5%	31.0%	35.2%	31.8%	33.0%	33.0%	Income Tax Rate	33.0%
						6.7%	6.5%	6.2%	7.6%	7.5%	5.9%	5.4%	6.7%	3.5%	3.6%	3.2%	3.3%	Net Profit Margin	3.8%
						40.2%	41.3%	42.3%	42.1%	35.5%	32.7%	37.8%	35.1%	39.6%	39.8%	39.5%	38.5%	Long-Term Debt Ratio	37.0%
						59.0%	58.1%	57.2%	57.4%	64.0%	66.7%	61.7%	64.5%	60.3%	60.1%	60.5%	61.5%	Common Equity Ratio	63.0%
						1165.2	1255.1	1300.6	1322.6	1230.1	1061.2	1180.1	1128.9	1251.5	1246.0	1260	1280	Total Capital ($mill)	1345
						1779.3	1771.9	1735.8	1731.8	1735.2	1729.6	1768.6	1796.8	2484.2	2549.8	2630	2700	Net Plant ($mill)	2930
						10.1%	11.1%	11.1%	9.9%	10.9%	13.7%	12.3%	12.2%	8.3%	8.8%	9.0%	9.5%	Return on Total Cap'l	10.0%
						14.3%	16.4%	16.6%	14.5%	15.4%	19.1%	18.6%	17.5%	12.3%	13.1%	12.5%	12.5%	Return on Shr. Equity	13.5%
						14.4%	16.6%	16.7%	14.6%	15.4%	19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	12.5%	Return on Com Equity	13.5%
						5.0%	7.6%	7.6%	5.4%	6.2%	8.5%	7.9%	6.5%	1.5%	2.1%	1.7%	2.3%	Retained to Com Eq	2.9%
						65%	54%	55%	63%	60%	56%	58%	63%	88%	84%	86%	82%	All Div'ds to Net Prof	78%

CAPITAL STRUCTURE as of 3/31/05
Total Debt $530.0 mill. Due in 5 Yrs $665.0 mill.
LT Debt $495.4 mill. LT Interest $20.0 mill.
(Total interest coverage: 4.5x)

No Defined Benefit Pension Plan

Pfd Stock $1.6 mill. Pfd Div'd Nil

Common Stock 44,136,171 shares as of 4/29/05

MARKET CAP: $1.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2003	2004	3/31/05
Cash Assets	83.2	83.2	93.5
Other	832.7	937.7	784.4
Current Assets	915.9	1020.9	877.9
Accts Payable	385.4	502.9	369.5
Debt Due	575.0	490.2	34.6
Other	108.3	178.3	585.3
Current Liab.	1068.7	1171.4	989.4
Fix. Chg. Cov.	437%	428%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	6.0%	9.0%	3.5%
"Cash Flow"	3.5%	1.5%	3.0%
Earnings	2.0%	-0.5%	1.0%
Dividends	4.5%	4.5%	1.5%
Book Value	2.5%	1.0%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	551.1	391.8	249.8	704.7	1897.4
2003	1171.3	452.8	294.8	743.8	2662.7
2004	1115.7	429.5	299.9	894.6	2739.7
2005	1179.8	445	315	1010.2	2950
2006	1200	455	320	1025	3000

Cal-endar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.82	.50	.67	.89	2.88
2003	1.11	.21	.01	.78	2.11
2004	.96	.44	d.26	1.08	2.22
2005	.98	.30	d.10	.92	2.10
2006	1.00	.40	d.15	1.00	2.25

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.415	.44	.44	.44	1.74
2002	.46	.46	.46	.46	1.84
2003	.46	.465	.465	.465	1.86
2004	.465	.465	.465	.465	1.86
2005	.465	.465			

BUSINESS: Nicor Inc. is a holding company with gas distribution as its primary business. Serves over 2.1 million customers in northern and western Illinois. 2004 gas delivered: 473.2 bcf, incl. 217.7 bcf from transportation. 2004 gas sales (255.5 bcf): residential, 80%; commercial, 17%; industrial, 3%. Principal supplying pipelines: Natural Gas Pipeline, Midwestern Gas, and Northern Natural. Current operations include Tropical Shipping subsidiary and several energy related ventures. Divested inland barging, 7/86; contract drilling, 9/86; oil and gas E&P, 6/93. Has about 3,600 employees, 23,700 stkhldrs. Off./dir. own about 1.9% of cmmn. stk. (4/05 proxy). CEO: Russ Strobel. Inc.: IL. Address: 1844 Ferry Road, Naperville, IL 60563. Telephone: 630-305-9500. Internet: www.nicor.com.

Nicor, Inc. will probably post weaker earnings in 2005. Profits should be weighed down by the underperforming gas distribution business, which has incurred higher operating and maintenance expenses. Indeed, such costs have continued to rise over the past couple of years due to a number of factors, such as an increase in labor and benefit-related expenses. Also, the surge in natural gas prices has led the company to raise its bad debt provisions. This negative trend will probably continue through the balance of the year. Our assumptions are largely based on near-term natural gas prices, as well as the greater capital costs necessary to sustain and expand Nicor's service territories.

Rate relief is still pending. Last November, the company made an initial filing with the Illinois Commerce Commission (ICC), requesting an increase in business and residential rates of $83.3 million in an effort to recoup operating costs. In addition, Nicor has proposed to pass on approximately two-thirds of all bad debt expenses to customers. We note that this is the company's first rate filing in nearly 10 years, as it absorbed incremental operating costs in that time. However, it remains uncertain if the company will receive the full amount of relief. A decision is expected to be reached in the fourth quarter.

The long-term earnings picture is less clear. We assume that the ICC will provide Nicor with some financial assistance, contributing to an earnings recovery in the coming year. But our earnings projections are subject to revision once the final order is delivered.

A ramp-up in capital spending may well hamper dividend growth. The company's capital expenditure budget for 2005 is up 20%, to $225 million. Given the larger capital outlays, Nicor should find it more challenging to increase the dividend payout in the foreseeable future. In the last two years, an unusually high percentage of net income was required to support the current dividend rate.

Falling bond yields are supporting untimely Nicor stock. But under current market conditions, the company has not been able to generate sufficient revenue to offset rising operating costs. Limited dividend growth also warrants concern.

Charles W. Noh *June 17, 2005*

(A) Based on primary earnings thru. '96, then diluted. Excl. nonrecurring gains/(loss): '89, 7¢; '97, 6¢; '98, 11¢; '99, 5¢; '00, ($1.96); '01, 16¢; '03, (27¢); '04, (52¢). Excl. items from discontinued ops.: '93, 4¢; '96, 30¢. Next earnings report due early August. (B) Dividends historically paid early February, May, August, November. ■ Dividend reinvestment plan available. (C) In millions, adjusted for stock split. (D) 2002 quarters do not sum to total due to change in shares outstanding.

Company's Financial Strength	A
Stock's Price Stability	65
Price Growth Persistence	65
Earnings Predictability	80

N.W. NAT'L GAS NYSE-NWN

RECENT PRICE	36.30	P/E RATIO	15.8 (Trailing: 17.7 / Median: 14.0)	RELATIVE P/E RATIO	0.86	DIV'D YLD	3.7%	VALUE LINE

TIMELINESS **3** Raised 3/11/05
SAFETY **1** Raised 3/18/05
TECHNICAL **3** Lowered 12/24/04
BETA .70 (1.00 = Market)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	24.3	22.8	25.9	31.4	30.8	27.9	27.5	26.8	30.7	31.3	34.1	37.8
Low:	18.8	18.3	20.8	23.0	24.3	19.5	17.8	21.7	23.5	24.0	27.5	32.4

Target Price Range 2008 | 2009 | 2010

2008-10 PROJECTIONS

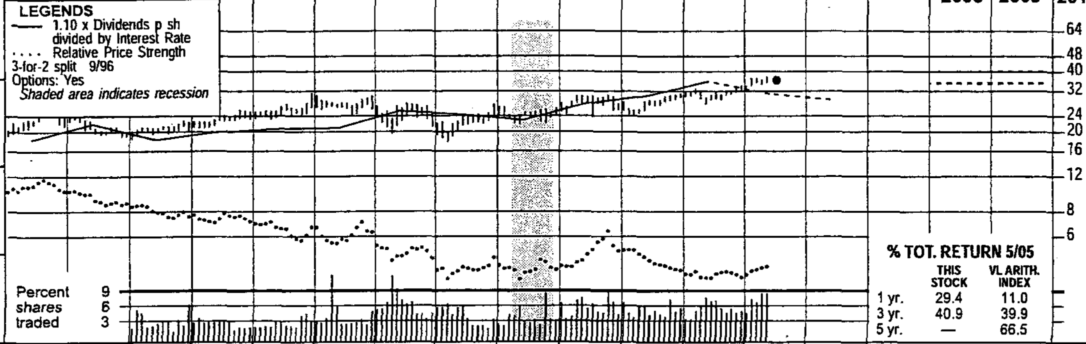
	Price	Gain	Ann'l Total Return
High	40	(+10%)	6%
Low	35	(-5%)	3%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	1	0	0	0
Options	0	2	3	0	3	3	0	4	2
to Sell	0	1	2	0	1	3	0	4	2

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	55	51	58
to Sell	57	50	51
Hld's(000)	12727	12975	12963



% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	29.4	11.0
3 yr.	40.9	39.9
5 yr.	—	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
15.22	17.02	16.74	14.10	18.15	18.30	16.02	16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	*29.20*	*30.55*	Revenues per sh	*35.00*
2.85	3.22	2.57	3.25	3.74	3.50	3.41	3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	*4.50*	*4.70*	"Cash Flow" per sh	*5.50*
1.58	1.62	.67	.74	1.74	1.63	1.61	1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	*2.30*	*2.40*	Earnings per sh A	*2.70*
1.07	1.10	1.13	1.15	1.17	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	*1.33*	*1.36*	Div'ds Decl'd per sh B■	*1.50*
3.36	3.85	3.58	3.73	3.61	4.23	3.02	3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	*5.00*	*5.00*	Cap'l Spending per sh	*5.00*
12.04	12.61	12.23	12.41	13.08	13.63	14.55	15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	*21.45*	*22.50*	Book Value per sh C	*25.60*
17.14	17.41	17.68	19.46	19.77	20.13	22.24	22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	*27.75*	*28.00*	Common Shs Outst'g D	*28.50*
9.8	10.2	28.1	27.0	12.9	13.0	12.9	11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.74	.76	1.79	1.64	.76	.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.89	*Value Line*		Relative P/E Ratio	*.90*
6.9%	6.7%	5.9%	5.7%	5.2%	5.5%	5.7%	5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
356.3	380.3	361.8	416.7	455.8	532.1	650.3	641.4	611.3	707.6	*810*	*855*	Revenues ($mill)	*1000*
38.1	46.8	43.1	27.3	44.9	47.8	50.2	43.8	46.0	50.6	*63.5*	*67.0*	Net Profit ($mill)	*77.0*
36.8%	36.9%	32.9%	31.0%	35.4%	35.9%	35.4%	34.9%	33.7%	34.4%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
10.7%	12.3%	11.9%	6.6%	9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	*7.8%*	*7.8%*	Net Profit Margin	*7.7%*
43.5%	41.4%	46.0%	45.0%	46.0%	45.1%	43.0%	47.6%	49.7%	46.0%	*45.5%*	*45.0%*	Long-Term Debt Ratio	*46.0%*
50.3%	52.8%	49.0%	50.6%	49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	*54.5%*	*55.0%*	Common Equity Ratio	*54.0%*
643.3	657.4	748.0	815.6	861.5	887.8	880.5	937.3	1006.6	1052.5	*1100*	*1150*	Total Capital ($mill)	*1360*
697.2	745.3	827.5	894.7	895.9	934.0	965.0	995.6	1205.9	1318.4	*1370*	*1430*	Net Plant ($mill)	*1625*
7.7%	8.9%	7.4%	5.0%	6.8%	6.7%	6.9%	5.9%	5.7%	5.9%	*7.0%*	*7.0%*	Return on Total Cap'l	*8.0%*
10.5%	12.1%	10.7%	6.1%	9.7%	9.8%	10.0%	8.9%	9.1%	8.9%	*10.5%*	*10.5%*	Return on Shr. Equity	*10.5%*
10.9%	12.7%	11.0%	6.0%	9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	*10.5%*	*10.5%*	Return on Com Equity	*10.5%*
3.0%	5.0%	3.6%	NMF	2.8%	3.1%	3.5%	1.9%	2.6%	2.7%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
74%	63%	70%	118%	74%	70%	67%	79%	72%	69%	*58%*	*57%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 12/31/04
Total Debt $601.5 mill. **Due in 5 Yrs** $160.0 mill.
LT Debt $484.0 mill. **LT Interest** $33.0 mill.
Incl. $5.6 mill. 7¼% debs. due 3/1/12, each conv. into 50.25 com. shs. at $19.90.
(Total interest coverage: 3.2x)

Pension Assets-12/04 $168.3 mill. **Oblig.** $205.4 mill.

Pfd Stock None

Common Stock 27,546,719 shs.
MARKET CAP $1.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2002	2003	12/31/04
Cash Assets	7.3	4.7	5.2
Other	186.7	194.8	231.9
Current Assets	194.0	199.5	237.1
Accts Payable	74.4	86.0	102.5
Debt Due	89.8	85.2	117.5
Other	40.8	43.2	47.3
Current Liab.	205.0	214.4	267.3
Fx. Chg. Cov.	296%	280%	316%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	4.0%	8.0%	*6.0%*
"Cash Flow"	1.0%	1.5%	*6.5%*
Earnings	2.5%	3.0%	*7.5%*
Dividends	1.0%	1.0%	*2.5%*
Book Value	4.0%	3.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	278.6	101.9	78.7	182.2	641.4
2003	206.5	117.5	69.5	217.8	611.3
2004	254.5	109.7	81.4	262.0	707.6
2005	308.8	*125*	*90.0*	*286.2*	*810*
2006	*325*	*133*	*97.0*	*300*	*855*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1.32	d.13	d.26	.69	1.62
2003	1.01	.17	d.25	.83	1.76
2004	1.24	d.03	d.30	.95	1.86
2005	1.43	*.17*	*d.30*	*1.00*	*2.30*
2006	*1.50*	*.17*	*d.31*	*1.04*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.31	.31	.31	.315	1.25
2002	.315	.315	.315	.315	1.26
2003	.315	.315	.315	.325	1.27
2004	.325	.325	.325	.325	1.30
2005	.325	.325			

BUSINESS: Northwest Natural Gas Co. (doing business as NW Natural) distributes natural gas at retail to 90 communities, 596,000 customers, in Oregon (96% of revs.) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.4 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline sys. to bring gas to market. Owns local underground storage. Rev. breakdown: resident'l & comm'l, 84%; ind., 10%; transport. and other, 6%. Employs 1,291. Has about 10,000 com. shrhldrs. Insiders own about 1% of com. Ch. Exec. Off.: Richard Woolworth. Inc.: OR. Addr.: 220 N.W. 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Web: www.nwnatural.com.

Northwest Natural has gained a good measure of investor confidence as an income stock. The returns available from high-quality fixed-income securities serve as Wall Street's benchmark for setting the yields on utility shares. In NW Natural's case, the current yield is moderately below the gas-stock average. That's because the utility's improved earnings promise of late has raised dividend-growth expectations, giving this stock an added prop.

This regulated gas distributor does business in a diversified and growing economy. Customer rolls in the Pacific Northwest are expanding at about 3% a year, thanks to new residential and commercial construction and conversions to gas from alternate fuels and power in older homes. Today, NW Natural has only about 50% of the region's home-heating market, and natural gas still holds an overall economic edge over fuel oil and electricity. So, with adequate gas supplies available from U.S. and Canadian fields, we expect the company to continue building its market share and sustain enough earning power to keep the dividend growing by 2% a year, or better, into 2007.

But there are risks. NW Natural appears to be getting fair treatment from its state regulators. The allowed return on common equity is a bit more than 10%, taking into account today's low borrowing costs. Giving the utility an added advantage, however, is a newly ordered weather normalization tariff that serves to negate the effect of winter temperature extremes. It should permit the utility a smoother upward earnings curve and afford management a more predictable cash flow for financial planning and dividend decisions. The new rate design worked nicely to NW Natural's favor last winter, enabling profits to move higher when thermometer readings were above normal. But looking ahead a year or two, the prospect of rising interest rates presents a potential investment risk, in that NW Natural's request for higher tariffs to cover increased borrowing costs might well require many months of oversight review. And a profit squeeze due to regulatory lag may preclude a dividend hike, with the general rise in bond yields likely putting more downward pressure on this equity's price.

Gerald Holtzman *June 17, 2005*

(A) Diluted earnings per share. Excludes nonrecurring gain: '98, $0.15; '00, $0.11. Next earnings report due late July.
(B) Dividends historically paid in mid-February, mid-May, mid-August, and mid-November.
■ Div'd reinvestment plan available.
(C) Includes intangibles. At 12/31/04: $4.21/sh.
(D) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	65

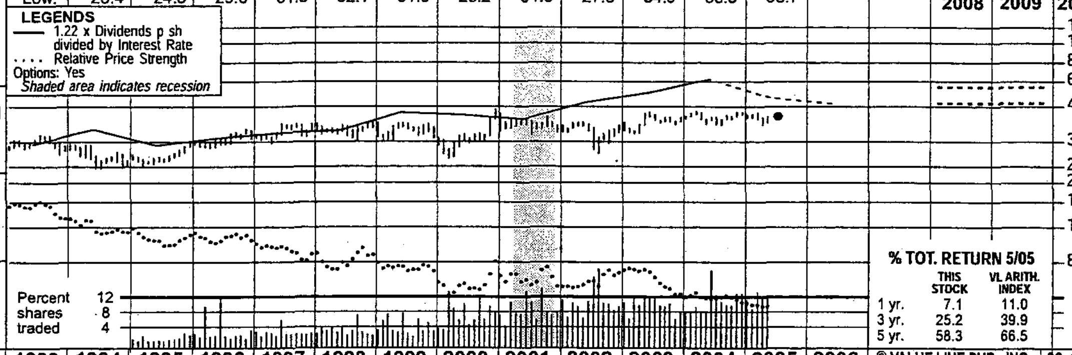
PEOPLES ENERGY NYSE-PGL

RECENT PRICE	42.98	P/E RATIO	16.2 (Trailing: 21.6 / Median: 14.0)	RELATIVE P/E RATIO	0.89	DIV'D YLD	5.1%	VALUE LINE

TIMELINESS **5** Lowered 2/4/05
SAFETY **1** Raised 9/29/95
TECHNICAL **3** Lowered 3/4/05
BETA .80 (1.00 = Market)

High:	32.1	32.0	37.4	39.9	40.1	40.3	46.9	44.6	40.4	45.3	46.0	45.1	
Low:	23.4	24.3	29.6	31.3	32.1	31.8	26.2	34.3	27.8	34.9	38.5	38.7	

Target Price Range
2008 | 2009 | 2010



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+40%)	13%
Low	50	(+15%)	8%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	1	0	0	0	0	0	0	1
Options	0	0	0	0	0	0	0	2	0
to Sell	0	0	0	0	0	0	0	3	0

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	80	98	94
to Sell	72	54	73
Hld's(000)	19912	21183	19746

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	7.1	11.0
3 yr.	25.2	39.9
5 yr.	58.3	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
36.42	35.63	33.69	31.54	36.09	36.70	29.60	34.29	36.34	32.28	33.66	40.16	64.13	41.81	58.28	59.90	*63.70*	*62.90*	Revenues per sh A	*76.15*
3.92	3.74	3.73	3.67	3.85	3.99	3.68	4.98	4.92	4.44	4.74	5.58	5.84	5.59	5.88	5.32	*5.80*	*6.05*	"Cash Flow" per sh	*7.15*
2.39	2.07	2.05	2.06	2.11	2.13	1.78	2.96	2.81	2.25	2.39	2.71	3.16	2.80	2.87	2.18	*2.60*	*2.70*	Earnings per sh B	*3.20*
1.58	1.65	1.71	1.76	1.78	1.80	1.80	1.82	1.87	1.91	1.95	2.00	2.04	2.07	2.12	2.16	*2.18*	*2.20*	Div'ds Decl'd per sh C ■	*2.32*
4.15	3.15	3.10	3.40	3.77	2.50	2.75	2.45	2.55	4.05	6.45	7.02	7.52	5.66	5.10	5.02	*4.60*	*4.75*	Cap'l Spending per sh	*6.55*
16.20	16.61	16.95	17.72	18.02	18.39	18.38	19.49	20.43	21.03	21.66	22.02	22.76	22.74	23.11	23.06	*23.30*	*24.10*	Book Value per sh D	*29.45*
32.62	32.70	32.76	34.77	34.88	34.87	34.91	34.96	35.07	35.26	35.49	35.30	35.40	35.46	36.69	36.69	*38.00*	*38.00*	Common Shs Outst'g E	*35.00*
7.9	11.2	11.8	13.1	15.0	13.3	14.7	10.7	12.7	16.2	15.5	12.1	12.3	13.3	13.4	19.1	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.60	.83	.75	.79	.89	.87	.98	.67	.73	.84	.88	.79	.63	.73	.76	1.02	*Value Line*		Relative P/E Ratio	*1.15*
8.4%	7.1%	7.0%	6.5%	5.6%	6.3%	6.9%	5.7%	5.2%	5.2%	5.3%	6.1%	5.2%	5.5%	5.5%	5.2%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 3/31/05

Total Debt $895.6 mill. Due in 5 Yrs $315.0 mill.

LT Debt $895.6 mill. LT Interest $50.0 mill.
(Total interest coverage: 4.7x)

Pension Assets-9/04 $544.9 mill.
Oblig. $515.8 mill.

Pfd Stock None

Common Stock 38,018,378 shs.
as of 4/29/05
MARKET CAP: $1.6 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
1033.4	1198.7	1274.4	1138.1	1194.4	1417.5	2270.2	1482.5	2138.4	2260.2	*2420*	*2390*	Revenues ($mill) A	*2665*
62.2	103.4	98.4	79.4	84.8	96.1	111.7	99.3	103.9	81.6	*100*	*105*	Net Profit ($mill)	*110*
34.4%	37.6%	36.4%	36.2%	35.9%	34.1%	35.4%	34.2%	36.3%	31.7%	*35.5%*	*35.5%*	Income Tax Rate	*35.5%*
6.0%	8.6%	7.7%	7.0%	7.1%	6.8%	4.9%	6.7%	4.9%	3.6%	*4.1%*	*4.4%*	Net Profit Margin	*4.1%*
49.2%	43.6%	42.4%	41.1%	40.4%	35.1%	44.4%	40.7%	46.7%	50.8%	*50.0%*	*49.5%*	Long-Term Debt Ratio	*46.5%*
50.8%	56.4%	57.6%	58.9%	59.6%	64.9%	55.6%	59.3%	53.3%	49.2%	*50.0%*	*50.5%*	Common Equity Ratio	*53.5%*
1263.6	1208.3	1243.5	1258.0	1290.5	1196.7	1449.8	1360.3	1592.3	1767.5	*1775*	*1805*	Total Capital ($mill)	*1920*
1373.1	1381.1	1402.2	1446.7	1519.8	1645.3	1753.9	1773.9	1838.2	1904.2	*1970*	*2035*	Net Plant ($mill)	*2305*
7.0%	10.3%	9.5%	7.8%	8.0%	9.5%	9.3%	8.4%	8.1%	6.0%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
9.7%	15.2%	13.7%	10.7%	11.0%	12.4%	13.9%	12.3%	12.3%	9.4%	*11.5%*	*11.5%*	Return on Shr. Equity	*10.5%*
9.7%	15.2%	13.7%	10.7%	11.0%	12.4%	13.9%	12.3%	12.3%	9.4%	*11.5%*	*11.5%*	Return on Com Equity	*10.5%*
NMF	5.9%	4.7%	1.7%	2.1%	3.4%	5.0%	3.3%	3.4%	.2%	*2.0%*	*2.0%*	Retained to Com Eq	*3.0%*
101%	61%	66%	84%	81%	73%	64%	73%	73%	97%	*83%*	*80%*	All Div'ds to Net Prof	*74%*

CURRENT POSITION ($MILL.)	2003	2004	3/31/05
Cash Assets	33.0	21.1	100.5
Other	457.1	531.3	715.7
Current Assets	490.1	552.4	816.2
Accts Payable	236.6	144.7	220.8
Debt Due	207.9	55.6	- -
Other	156.1	335.8	510.9
Current Liab.	600.6	536.1	731.7
Fix. Chg. Cov.	259%	304%	388%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	5.0%	10.0%	*2.5%*
"Cash Flow"	4.5%	4.0%	*2.0%*
Earnings	3.5%	2.0%	*1.0%*
Dividends	1.5%	2.0%	*1.5%*
Book Value	2.5%	2.5%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	377.5	522.8	347.1	235.1	1482.5
2003	549.2	903.8	398.1	287.3	2138.4
2004	604.9	927.0	401.1	327.1	2260.2
2005	737.4	1026.9	*360*	*295.7*	*2420*
2006	*730*	*1015*	*355*	*290*	*2390*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	.87	1.55	.33	.05	2.80
2003	.87	1.77	.22	.04	F 2.87
2004	.85	1.46	.15	d.27	F 2.18
2005	.77	1.37	*.31*	*.15*	*2.60*
2006	*.83*	*1.51*	*.25*	*.11*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.50	.51	.51	.51	2.03
2002	.51	.52	.52	.52	2.07
2003	.53	.53	.53	.53	2.12
2004	.54	.54	.54	.54	2.16
2005	.545	.545			

BUSINESS: Peoples Energy Corporation distributes natural gas via its utility subsidiaries, Peoples Gas Light & Coke Co. (approx. 1,000,000 customers at 9/30/04) and North Shore Gas Co. (150,000), in Chicago and northeastern Illinois. Fiscal 2004 volume: 229 bill. cu. ft.: residential, 51%; commercial, 9%; industrial, 2%; other, 38%. Main supplier is Natural Gas Pipeline Co. of America. Purchased gas costs and revenue taxes accounted for 67% of gas revenues in fiscal '04. Depreciation rate: 3.5%. Est'd plant age: 10 years. Has 2,400 employees, 20,988 shareholders. Directors own 1% of common (1/05 Proxy). Chairman and CEO: Thomas M. Patrick. Inc.: Illinois. Address: 130 East Randolph Drive, Chicago, IL 60601. Telephone: 312-240-4000. Internet: www.pecorp.com.

Peoples Energy continues to struggle with warmer weather. During the second fiscal quarter (year ends September 30th), temperatures in the company's service territory ran 5.3% warmer than normal and almost 4% warmer than last year. This resulted in a $5 million shortfall in operating income, and, consequently, share net of $1.37 was well below our $1.49 estimate. Year-to-date, weather has negatively impacted operating income by $11 million. Peoples will be filing for a weather normalization adjustment with the Illinois Commerce Commission that should ultimately reduce the negative impact of temperature volatility. However, we expect this will be a relatively long process and so no near-term relief is likely. Stronger results in the company's Retail and Power Generation segments were not enough to offset weaker performances in the Gas Distribution unit. What's more,

Production volumes in the Oil and Gas segment dipped again. Overall production in the quarter declined nearly 20% year over year and 6% sequentially. Management once again cited ongoing timing delays with the company's drilling program, in addition to well performance issues, pipeline curtailments, and equipment downtime. Peoples expects volume growth to pick up in the second half of 2005, but we have taken a more conservative standpoint, as we suspect it may take longer than anticipated to get production growth back on track.

We have lowered our earnings estimate for fiscal 2005 by a nickel, to $2.60. This is at the lower end of management's target range. We believe Peoples will not be able to overcome the effects of the warm winter and oil production shortfalls. At this level of earnings, the company's payout ratio stands at over 80%, which is higher than the historical average, and prompts us to wonder whether dividend increases will be slow to come in the future. Noncore operations have not been enough to cover the faltering gas distribution business. That said, we believe the dividend is safe, though we expect management might choose keep any quarterly increases to one-half cent per share, rather than the one-cent gains shareholders were used to in the past.

Edward Plank *June 17, 2005*

(A) Fiscal year ends Sept. 30th.
(B) Basic earnings per share. Excludes acct'g gains/(losses): '89, $0.30; '99, $0.22; '00, ($0.27). Next earnings report due late July.
(C) Dividends historically paid mid-January, April, July, October. ■ Dividend reinvestment plan available.
(D) Includes deferred charges. At 9/30/04: $74.0 mill., $1.96/sh.
(E) In millions.
(F) Earnings don't sum due to change in shares outstanding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	80

PIEDMONT NAT'L. NYSE-PNY

RECENT PRICE 23.71 | P/E RATIO 18.2 (Trailing: 20.9, Median: 16.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 5 Lowered 2/11/05
SAFETY 2 New 7/27/90
TECHNICAL 4 Lowered 6/17/05
BETA .75 (1.00 = Market)

High:	11.7	12.4	12.9	18.2	18.1	18.3	19.7	19.0	19.0	22.0	24.3	25.0	
Low:	9.0	9.1	10.3	11.0	13.9	14.3	11.8	14.6	13.7	16.6	19.2	21.8	

Target Price Range 2008 | 2009 | 2010

2008-10 PROJECTIONS

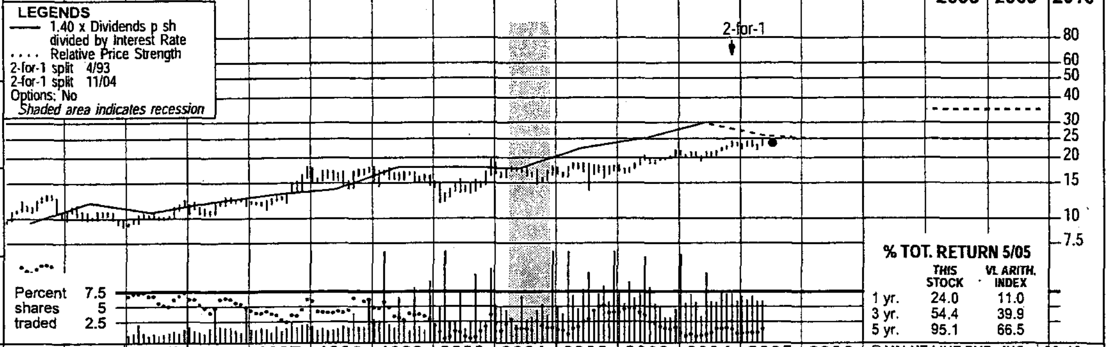
	Price	Gain	Ann'l Total Return
High	35	(+50%)	13%
Low	25	(+5%)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	8	0	9	0	10	9	10	8	9
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	1	1	0	1	1	0	1

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	61	80	80
to Sell	52	58	58
Hld's(000)	30297	30343	30461



% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	24.0	11.0
3 yr.	54.4	39.9
5 yr.	95.1	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
10.12	9.42	8.32	8.91	10.57	10.82	8.76	11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	*22.20*	*20.80*	Revenues per sh A	*24.10*
.96	.97	.78	1.07	1.14	1.13	1.25	1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	*2.30*	*2.50*	"Cash Flow" per sh	*3.15*
.61	.61	.44	.70	.73	.68	.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	*1.25*	*1.30*	Earnings per sh B	*1.60*
.39	.42	.44	.46	.48	.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.86	*.92*	*.98*	Div'ds Decl'd per sh C■	*1.10*
1.56	1.62	1.37	1.41	1.58	1.95	1.72	1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	*1.35*	*1.40*	Cap'l Spending per sh	*1.45*
4.37	4.58	4.83	5.13	5.45	5.68	6.16	6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	*11.45*	*11.90*	Book Value per sh D	*13.75*
41.57	42.87	49.46	51.59	52.30	53.15	57.67	59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	*77.00*	*76.00*	Common Shs Outst'g E	*73.00*
10.3	11.3	16.3	12.3	15.4	15.7	13.8	13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
.78	.84	1.04	.75	.91	1.03	.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.87	*Value Line*		Relative P/E Ratio	*1.25*
6.3%	6.0%	6.0%	5.3%	4.3%	4.8%	5.4%	4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 1/31/05
Total Debt $849.5 mill. Due in 5 Yrs $275.0 mill.
LT Debt $660.0 mill. LT Interest $33.0 mill.
(LT interest earned: 4.1x; total interest coverage: 3.9x)

Pension Assets-10/04 $125.1 mill. **Oblig.** $149.7 mill.

Pfd Stock None

Common Stock 76,681,352 shs. as of 3/1/05

MARKET CAP: $1.8 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
505.2	685.1	775.5	765.3	686.5	830.4	1107.9	832.0	1220.8	1529.7	*1710*	*1580*	Revenues ($mill) A	*1760*
40.3	48.6	55.2	60.3	58.2	64.0	65.5	62.2	74.4	95.2	*95.0*	*100*	Net Profit ($mill)	*120*
38.7%	38.9%	39.1%	39.2%	39.7%	34.7%	34.6%	33.1%	34.8%	35.1%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
8.0%	7.1%	7.1%	7.9%	8.5%	7.7%	5.9%	7.5%	6.1%	6.2%	*5.6%*	*6.3%*	Net Profit Margin	*6.7%*
50.4%	50.3%	47.6%	44.7%	46.2%	46.1%	47.6%	43.9%	42.2%	43.6%	*43.0%*	*42.0%*	Long-Term Debt Ratio	*37.5%*
49.6%	49.7%	52.4%	55.3%	53.8%	53.9%	52.4%	56.1%	57.8%	56.4%	*57.0%*	*58.0%*	Common Equity Ratio	*62.5%*
716.0	777.1	800.8	829.3	914.7	978.4	1069.4	1051.6	1090.2	1514.9	*1540*	*1565*	Total Capital ($mill)	*1605*
801.3	862.0	941.7	990.6	1047.0	1072.0	1114.7	1158.5	1812.3	1849.8	*1900*	*1950*	Net Plant ($mill)	*2150*
7.5%	8.2%	8.9%	9.2%	8.1%	8.3%	7.9%	7.8%	8.6%	7.8%	*7.5%*	*8.0%*	Return on Total Cap'l	*9.0%*
11.4%	12.6%	13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	*11.0%*	*11.0%*	Return on Shr. Equity	*12.0%*
11.4%	12.6%	13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	*11.0%*	*11.0%*	Return on Com Equity	*12.0%*
2.7%	3.9%	4.6%	4.7%	3.3%	3.5%	3.0%	1.7%	3.1%	3.7%	*2.5%*	*3.0%*	Retained to Com Eq	*4.0%*
76%	69%	65%	65%	72%	71%	75%	83%	74%	66%	*75%*	*74%*	All Div'ds to Net Prof	*67%*

CURRENT POSITION ($MILL.)	2003	2004	1/31/05
Cash Assets	11.2	5.7	25.5
Other	296.4	329.5	538.8
Current Assets	307.6	335.2	564.3
Accts Payable	90.9	99.6	160.5
Debt Due	557.1	109.5	189.5
Other	77.2	97.1	134.1
Current Liab.	725.2	306.2	484.1
Fix. Chg. Cov.	288%	356%	378%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	5.5%	7.0%	*5.0%*
"Cash Flow"	6.5%	4.0%	*6.5%*
Earnings	4.5%	3.0%	*7.5%*
Dividends	5.5%	5.0%	*4.0%*
Book Value	6.0%	5.5%	*7.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2002	288.7	293.9	127.9	121.5	832.0
2003	493.5	407.8	140.1	179.4	1220.8
2004	618.8	482.4	214.7	213.8	1529.7
2005	680.6	*540*	*250*	*239.4*	*1710*
2006	*635*	*500*	*220*	*225*	*1580*

Fiscal Year Ends	EARNINGS PER SHARE A B F Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2002	.63	.64	d.14	d.18	.95
2003	.87	.47	d.15	d.08	1.11
2004	1.03	.54	d.11	d.21	1.27
2005	.93	*.54*	*d.11*	*d.11*	*1.25*
2006	*.98*	*.53*	*d.11*	*d.10*	*1.30*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.183	.193	.193	.193	.76
2002	.20	.20	.20	.20	.80
2003	.208	.208	.208	.208	.83
2004	.215	.215	.215	.215	.86
2006	.23	.23			

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 960,000 customers in North Carolina, South Carolina, and Tennessee. 2004 revenue mix: residential (43%), commercial (25%), industrial (9%), other (23%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 53.3% of revenues. '04 depreciation rate: 3.3%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 2,155 employees, 16,433 shareholders of record. CEO & President: Thomas E. Skains. Incorporated: North Carolina. Address: 1915 Rexford Road, P.O. Box 33068 Charlotte, NC 28233. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas' fiscal second quarter (ended April 30th) earnings were likely in line with our expectations. Share net probably topped out at about $0.54, flat versus last year. For the whole of fiscal 2005, *we estimate a slight* dip in EPS. Higher gas prices continue to pose somewhat of a risk to our estimate, as they tend to increase gas carrying costs and uncollectibles from low-income customers. We believe Piedmont's customer growth rate will remain in the above average 3%-3.5% range, given the proliferation of new housing starts in the company's service territories.

Potential rate relief may prove our earnings target conservative. The company has filed a general rate case in North Carolina. As part of the filing, management will propose to consolidate all of its North Carolina operations under one tariff, one set of service regulations, and one rate structure. This will encompass almost 70% of the rate base. The filing seeks to implement the new rates by November. Separately, the governor of South Carolina signed natural gas rate stabilization legislation that essentially allows gas utilities in to file for annual rate adjustments.

Non-utility businesses are likely to comprise a greater portion of future earnings. Regulated operations continue to make up the lion's share of Piedmont's total income. And while management intends to remain focused on being a gas utility, unregulated activities, which include SouthStar Energy and the Pine Needle and Cardinal Pipeline joint ventures, should consistently contribute to the bottom line. We expect Piedmont to continue to pursue strategic investments (likely storage or pipeline assets), a strategy that has permitted the company to diversify its earnings stream. Management intends to grow this segment to at least 15% of total earnings.

Though untimely, this issue is suitable for income-oriented accounts. Piedmont's dividend yield remains an attraction, and we expect steady increases in payments going forward. Currently, the yield stands at 3.9%, roughly average for the LDC group. Furthermore, risk should be held to a minimum, considering the stock's above average Safety grade.

Edward Plank *June 17, 2005*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due early August.
(C) Dividends historically paid mid-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges At 10/31/04: $5.3 million, 7¢/share.
(E) In millions, adjusted for stock splits.
(F) Quarters may not add to total due to change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	80

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE **28.70** | P/E RATIO **17.4** (Trailing: 17.6; Median: 13.0) | RELATIVE P/E RATIO **0.95** | DIV'D YLD **3.0%** | VALUE LINE

TIMELINESS **4** Lowered 12/17/04

SAFETY **2** Lowered 1/4/91

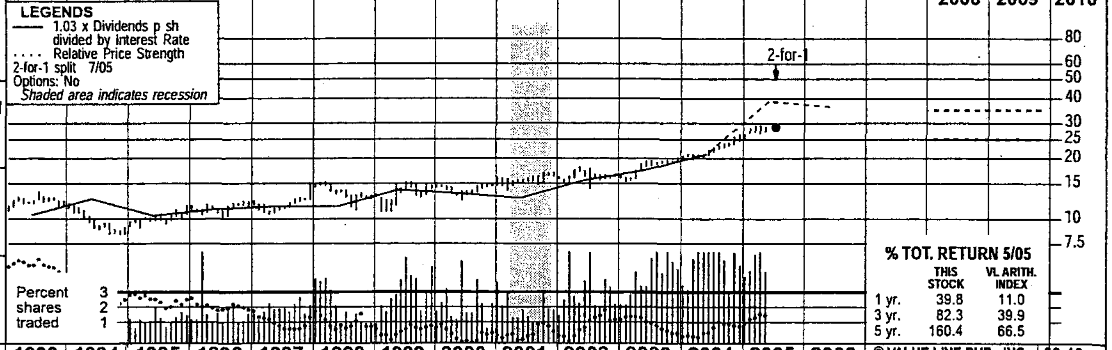
TECHNICAL **3** Raised 6/10/05

BETA .60 (1.00 = Market)

High:	12.0	11.8	12.3	15.3	15.4	15.4	15.1	17.0	18.3	20.3	26.5	29.7
Low:	8.3	8.9	10.1	10.5	11.0	10.8	12.3	13.8	14.1	15.3	19.7	24.9

Target Price Range 2008 2009 2010

LEGENDS
—— 1.03 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
Options: No
Shaded area indicates recession



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+20%)	8%
Low	25	(-15%)	1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	1	3

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	39	46	31
to Sell	35	35	51
Hld's(000)	12466	12938	12752

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	39.8	11.0
3 yr.	82.3	39.9
5 yr.	160.4	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
15.27	14.40	15.10	16.67	17.03	17.45	16.50	16.52	16.18	20.89	17.60	22.43	35.30	20.69	26.34	29.51	30.30	31.50	Revenues per sh	35.00
1.50	1.34	1.37	1.56	1.54	1.35	1.65	1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.60	2.75	"Cash Flow" per sh	3.10
.83	.67	.64	.81	.78	.61	.83	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.65	1.75	Earnings per sh A	2.00
.68	.70	.71	.71	.72	.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	.85	.90	Div'ds Decl'd per sh B ■	1.15
2.27	2.11	2.17	1.69	1.87	1.93	2.08	2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	2.25	2.65	Cap'l Spending per sh	3.10
6.74	6.79	6.77	6.95	7.17	7.23	7.34	8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	13.25	13.75	Book Value per sh C	15.80
16.96	18.06	18.48	19.00	19.61	21.43	21.44	21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.76	28.40	28.60	Common Shs Outst'g D	30.00
11.9	13.6	14.5	13.2	15.8	16.1	12.2	13.3	13.8	21.2	13.3	13.0	13.6	13.5	13.3	14.1	Bold figures are		Avg Ann'l P/E Ratio	14.0
.90	1.01	.93	.80	.93	1.06	.82	.83	.80	1.10	.76	.85	.70	.74	.76	.75	Value Line		Relative P/E Ratio	.95
6.9%	7.7%	7.6%	6.6%	5.9%	7.4%	7.2%	6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	estimates		Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 3/31/05
Total Debt $353.8 mill. Due in 5 Yrs $19.5 mill.
LT Debt $321.4 mill. LT Interest $20.0 mill.
(Total interest coverage: 5.8x)

Pension Assets-12/04 $107.5 mill. Oblig. $100.5 mill.

Pfd Stock $1.7 mill. Pfd Div'd $.1 mill.
16,904 Series B shs. 8% cum. ($100 par) callable 106.7

Common Stock 27,953,000 common shs.
Adjusted for 2 for 1 split on June 10th.
MARKET CAP: $800 million (Small Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
353.8	355.5	348.6	450.2	392.5	515.9	837.3	505.1	696.8	819.1	860	900	Revenues ($mill)	1050
17.8	18.5	18.4	13.8	22.0	24.7	26.8	29.4	34.6	43.0	47.0	49.0	Net Profit ($mill)	60.0
34.4%	35.5%	36.8%	46.2%	42.8%	43.1%	42.2%	41.4%	40.6%	40.9%	40.5%	40.5%	Income Tax Rate	40.5%
5.0%	5.2%	5.3%	3.1%	5.6%	4.8%	3.2%	5.8%	5.0%	5.2%	5.4%	5.5%	Net Profit Margin	5.6%
51.4%	46.1%	54.6%	57.3%	53.8%	54.1%	57.0%	53.6%	50.8%	48.7%	49.0%	49.0%	Long-Term Debt Ratio	49.0%
47.9%	53.2%	35.8%	33.5%	37.0%	37.6%	35.9%	46.1%	49.0%	51.0%	51.0%	51.0%	Common Equity Ratio	51.0%
328.4	324.8	387.1	401.1	405.9	443.5	516.2	512.5	608.4	675.0	725	770	Total Capital ($mill)	925
422.7	423.9	456.5	504.3	533.3	562.2	607.0	666.6	748.3	799.9	825	875	Net Plant ($mill)	1050
7.8%	7.9%	6.7%	5.3%	7.4%	7.4%	6.9%	7.6%	7.3%	7.9%	6.5%	6.5%	Return on Total Cap'l	6.5%
11.2%	10.5%	10.5%	8.1%	11.7%	12.1%	12.1%	12.4%	11.5%	12.4%	13.0%	12.5%	Return on Shr. Equity	12.5%
11.2%	10.6%	13.3%	10.3%	14.6%	14.8%	12.8%	12.5%	11.6%	12.5%	13.0%	12.5%	Return on Com Equity	12.5%
1.4%	1.6%	2.1%	NMF	4.2%	4.8%	3.5%	4.7%	5.0%	5.9%	6.5%	6.0%	Retained to Com Eq	6.0%
88%	85%	84%	112%	72%	67%	76%	62%	57%	52%	51%	53%	All Div'ds to Net Prof	52%

CURRENT POSITION ($MILL.)	2003	2004	3/31/05
Cash Assets	4.4	5.3	14.2
Other	261.4	278.6	129.9
Current Assets	265.8	283.9	144.1
Accts Payable	80.3	118.8	59.8
Debt Due	118.1	97.6	12.3
Other	70.1	68.9	65.0
Current Liab.	268.5	285.3	137.1
Fix. Chg. Cov.	378%	427%	446%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	4.0%	7.0%	5.5%
"Cash Flow"	4.5%	7.0%	5.5%
Earnings	6.5%	10.5%	5.5%
Dividends	1.0%	1.5%	5.0%
Book Value	4.5%	11.5%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	177.0	84.2	69.1	174.8	505.1
2003	279.9	106.2	90.1	220.6	696.8
2004	307.6	136.5	129.5	245.5	819.1
2005	328.5	145	140	246.5	860
2006	335	150	145	270	900

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.83	.03	d.14	.50	1.22
2003	.92	.08	d.07	.44	1.37
2004	.91	.15	.02	.50	1.58
2005	.96	.15	.02	.52	1.65
2006	.99	.18	.03	.55	1.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.182	.185	.185	.185	.74
2002	.185	.188	.188	.38	.94
2003	.193	.193	.193	.395	.78
2004	.202	.202	.202	.212	.82
2005	.212	.212			

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 314,000 customers in New Jersey's southern counties, which cover 2,500 square miles and include Atlantic City. Principal suppliers include *Transcontinental* Gas Pipeline and Columbia Gas Pipeline. Gas revenue mix '04: residential, 31%; commercial and industrial, 10%; transportion, including off-system sales and gas marketing, 54%; off-system, 4%; cogeneration & power generation, 1%. Has 643 employees. Offs./dirs. cntrl. 1.4% of com. shares; Dimensional Fund Advisors, 7.4% (3/05 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Rte. 54, Folsom, NJ 08037. Telephone: 609-561-9000. Web: www.sjindustries.com.

In the near term, South Jersey Industries is apt to produce strong results. On the nonutility side of the business, it has signed contracts to construct a landfill-gas generation facility in Warren County, N.J. This plant, which will be a sister to SJI's newly operational Egg Harbor facility, is scheduled to come on line by early 2006. In addition, the 2006 planned expansion of the Borgata Hotel's onsite energy production facility appears to be on track. We believe that these projects will total 4% to 5% of total revenue by 2007.

On the regulated utility side of the business, the company has filed for a rate increase. Utility operations comprise 60% of total revenue. The approval would provide welcome relief from the 12% increase in wholesale gas prices that has occurred over the previous 12 months. Considering this precipitous rise in prices, we feel that some measure of increase will be awarded. Nonetheless, as the approval of increases is difficult to predict, we have not adjusted our models to reflect it.

Nonutility initiatives should be the main driver of earnings growth into 2008-2010. The Borgata Hotel has plans to add a new building in 2007. This project would necessitate an additional expansion of the Borgata's onsite energy production facility operated under a 20-year contract by SJI's subsidiary, Marina Energy.

South Jersey's dividend yield is below average in the natural das distribution space. This low yield is predominately the result of SJI being a small, fast growing utility. Indeed, stronger earnings growth has driven up the share price 17% in six months. As a result, the company's dividend yield has dwindled. As such, income investors may choose to look elsewhere but...

Management has made a commitment to increase dividends between 3% and 6% per annum. Given our estimates, we feel that future increases will remain near the upper end of this range. Although a position in SJI may be well suited to investors who are willing to sacrifice some yield for capital appreciation potential, it may also interest yield-investors searching for a growing income stream.

Note: The June 10th 2-for-1 stock split is reflected in our presentation.

Edward C. Muztafago *June 17, 2005*

(A) Based on avg. shs. Excl. nonrecur. gain: '01, $0.13. Excl gain (losses) from discont. ops.: '96, $1.14; '97, ($0.24); '98, ($0.26); '99, ($0.02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09). Excl. gain due to acct'g change: '93, $0.04; '01, $0.14. Next egs. report due late July.
(B) Dividends paid early Jan., Apr., Jul., and Oct. ■ Div. reinvest. plan avail. (2% disc.).
(C) Incl. regulatory assets: in '04, $5.26 per shr.
(D) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	85

WGL HOLDINGS NYSE-WGL

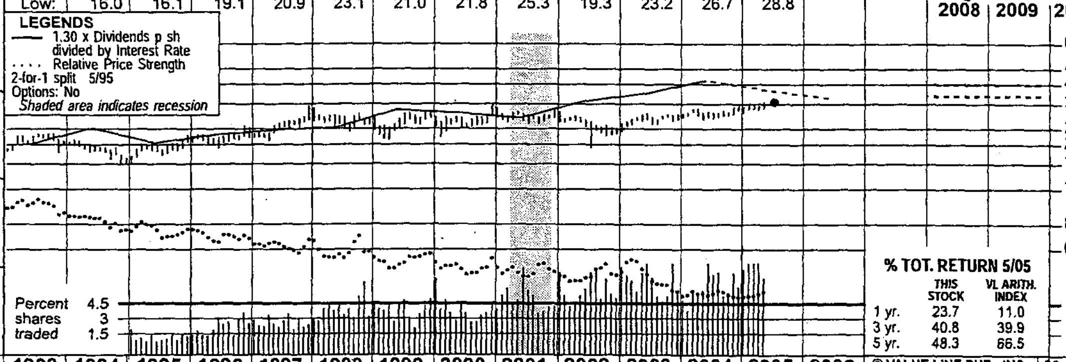
RECENT PRICE	32.72	P/E RATIO	16.0 (Trailing: 15.9 Median: 14.0)	RELATIVE P/E RATIO	0.87	DIV'D YLD	4.1%	VALUE LINE

TIMELINESS 4 Raised 2/11/05
SAFETY 1 Raised 4/2/93
TECHNICAL 3 Lowered 9/24/04
BETA .75 (1.00 = Market)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	21.3	22.4	25.0	31.4	30.8	29.4	31.5	30.5	29.5	28.8	31.4	33.5
Low:	16.0	16.1	19.1	20.9	23.1	21.0	21.8	25.3	19.3	23.2	26.7	28.8

Target Price Range 2008 | 2009 | 2010

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/95
Options: No
Shaded area indicates recession



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+20%)	9%
Low	35	(+5%)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	68	86	92
to Sell	51	60	62
Hld's(000)	23834	24821	26169

Percent shares traded 4.5 3 1.5

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	23.7	11.0
3 yr.	40.8	39.9
5 yr.	48.3	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
19.52	18.75	17.50	18.37	21.55	21.69	19.30	22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	*45.15*	*46.90*	Revenues per sh A	*54.40*
2.03	2.17	2.04	2.17	2.25	2.43	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	*3.90*	*4.05*	"Cash Flow" per sh	*4.85*
1.22	1.26	1.14	1.27	1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	*2.00*	*2.10*	Earnings per sh B	*2.60*
.97	1.01	1.05	1.07	1.09	1.11	1.12	1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	*1.33*	*1.34*	Div'ds Decl'd per sh C■	*1.40*
3.00	2.38	2.05	2.17	2.43	2.84	2.63	2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	*2.70*	*2.75*	Cap'l Spending per sh	*2.95*
9.86	10.17	9.63	10.66	11.04	11.51	11.95	12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	*17.60*	*18.40*	Book Value per sh D	*20.40*
38.70	39.23	39.89	40.62	41.50	42.19	42.93	43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	*48.70*	*48.70*	Common Shs Outst'g E	*48.70*
10.6	11.7	12.8	13.6	15.6	14.0	12.7	11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.80	.87	.82	.82	.92	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	*Value Line*		Relative P/E Ratio	*.95*
7.5%	6.9%	7.2%	6.2%	5.3%	5.6%	6.1%	5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 3/31/05
Total Debt $614.3 mill. Due in 5 Yrs $315.0 mill.
LT Debt $523.7 mill. LT Interest $40.0 mill.
(LT interest earned: 5.0x; total interest coverage: 4.8x)
Pension Assets-9/04 $683.1 mill. Oblig. $655.8 mill.
Preferred Stock $28.2 mill. Pfd Div'd $1.3 mill.

Common Stock 48,692,876 shs. as of 4/30/05
MARKET CAP: $1.6 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
828.7	969.8	1055.8	1040.6	972.1	1031.1	1446.5	1584.8	2064.2	2089.6	*2200*	*2285*	Revenues ($mill) A	*2650*
62.9	81.6	82.0	68.6	68.8	84.6	89.9	55.7	112.3	98.0	*100*	*105*	Net Profit ($mill)	*125*
37.4%	37.7%	36.9%	35.6%	36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
7.6%	8.4%	7.8%	6.6%	7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	*4.5%*	*4.6%*	Net Profit Margin	*4.7%*
37.8%	37.6%	41.1%	40.3%	41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	*38.5%*	*37.0%*	Long-Term Debt Ratio	*34.5%*
58.9%	59.4%	56.2%	57.1%	56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	*60.0%*	*61.5%*	Common Equity Ratio	*63.5%*
870.6	941.1	1049.0	1064.8	1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	*1485*	*1505*	Total Capital ($mill)	*1615*
1056.1	1130.6	1217.1	1319.5	1402.7	1460.3	1519.7	1606.8	1874.9	1915.6	*1950*	*2085*	Net Plant ($mill)	*2510*
8.7%	10.1%	9.3%	8.0%	7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	*6.5%*	*7.0%*	Return on Total Cap'l	*8.0%*
11.6%	13.9%	13.3%	10.8%	9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	*11.0%*	*11.0%*	Return on Shr. Equity	*12.0%*
12.0%	14.4%	13.7%	11.1%	9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	*11.0%*	*11.0%*	Return on Com Equity	*12.5%*
2.8%	5.6%	5.1%	2.5%	1.8%	3.7%	3.8%	NMF	6.2%	4.1%	*3.5%*	*4.0%*	Retained to Com Eq	*5.5%*
77%	62%	63%	78%	82%	69%	67%	112%	56%	65%	*67%*	*65%*	All Div'ds to Net Prof	*55%*

CURRENT POSITION ($MILL.)	2003	2004	3/31/05
Cash Assets	4.5	6.6	72.2
Other	404.4	426.3	559.6
Current Assets	408.9	432.9	631.8
Accts Payable	142.7	179.0	208.0
Debt Due	178.9	156.3	90.6
Other	64.5	77.6	273.6
Current Liab.	386.1	412.9	572.2
Fix. Chg. Cov.	487%	449%	460%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	6.5%	11.5%	5.5%
"Cash Flow"	4.5%	4.0%	5.5%
Earnings	3.0%	2.0%	6.5%
Dividends	1.5%	1.5%	1.5%
Book Value	4.0%	3.0%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	417.1	564.8	314.2	288.7	1584.8
2003	560.0	851.1	373.2	279.9	2064.2
2004	585.3	862.2	356.9	285.2	2089.6
2005	624.1	931.5	*369*	*275.4*	*2200*
2006	*650*	*935*	*390*	*310*	*2285*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	.66	1.09	d.14	d.47	1.14
2003	1.10	1.61	d.05	d.36	2.30
2004	.81	1.62	d.08	d.37	1.98
2005	.88	1.63	*d.15*	*d.36*	*2.00*
2006	*.93*	*1.58*	*d.08*	*d.33*	*2.10*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.31	.315	.315	.315	1.26
2002	.315	.318	.318	.318	1.27
2003	.318	.32	.32	.32	1.28
2004	.32	.325	.325	.325	1.30
2005	.325	.333			

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA. and MD. to resident'l and comm'l users (1,006,227 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. Has 1,914 employees. Off./dir. own less than 1% of the common stock (1/05 proxy). Chairman & CEO: J.H. DeGraffenreidt. Inc.: D.C. and VA. Address: 1100 H St., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings' March quarter was well ahead of our previous expectation. This was generated by temperatures that were colder than normal, along with strong results in the company's retail energy-marketing business. Too, over the 2008–2010 period, we expect the company's nonregulated segment to represent a greater proportion of total earnings (currently about 7%).

Net income from its nonregulated segment is doing well. The retail segment reported net income of $5.8 million this past quarter versus a net loss of $183,000 in the year-ago period. This reflects higher margins in the sale of natural gas. Moreover, losses in the heating, ventilating, and air-conditioning unit have narrowed so far versus last year, and management expects this unit to break even in 2005.

WGL will be replacing all of its mechanical couplings over 100 square miles in Prince George's County, Maryland. This is a result of a jump in the number of gas leaks. The company intends to fix the leaks within the next six months and replace all couplings in the system by December of 2007. This project is likely to cost $87 million, which does not include paving costs that may total an additional $50 million. By replacing these couplings rather than repairing them, the company can treat these costs as capital expenditures. WGL has filed with Maryland regulators for rate relief, and we expect the company to recover most, if not all, of the charges associated with this project.

The company has announced plans to construct a $60 million liquefied natural gas facility. This would have a capacity of one billion cubic feet of gas and be located in Chillum, Maryland. This location was selected because it will enhance pressure on the eastern portion of the system. This plant should allow WGL to purchase and store gas when demand and prices are lower, and deliver the gas to customers during peak times. It is scheduled to be in service for the 2008–2009 winter.

This stock is untimely, but holds appeal for income-oriented investors. The company has increased its dividend for 29 consecutive years, and offers a solid yield at 4.1%.

Evan I. Blatter *June 17, 2005*

(A) Beginning 1989, fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢).
Next earnings report due late July.
(C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '04: $156.5 million, $3.22/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	60

ATTACHMENT C

SOUTHWEST GAS NYSE-SWX

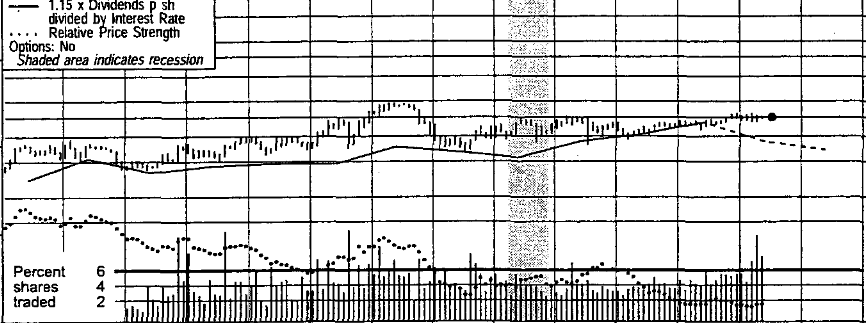
RECENT PRICE 24.97 | P/E RATIO 20.0 (Trailing: 18.4 / Median: 20.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 4 Lowered 5/6/05
SAFETY 3 Lowered 1/4/91
TECHNICAL 3 Raised 6/10/05
BETA .75 (1.00 = Market)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	19.4	18.4	19.9	20.3	26.9	29.5	23.0	24.7	25.3	23.6	26.2	26.1
Low:	13.8	13.6	14.9	16.1	17.3	20.4	16.9	18.6	18.1	19.3	21.5	23.5

Target Price Range 2008 | 2009 | 2010

LEGENDS
—— 1.15 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: No
Shaded area indicates recession



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+100%)	21%
Low	35	(+40%)	11%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	1	1	0	2	2	0	0	1
Options	1	0	0	1	5	1	0	0	1
to Sell	1	0	2	1	6	2	0	0	4

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	73	65	66
to Sell	31	36	45
Hld's(000)	21055	21987	22540

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	14.2	11.0
3 yr.	14.4	39.9
5 yr.	52.1	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
25.71	25.90	24.99	25.93	25.68	28.16	23.03	24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	*42.65*	*43.55*	Revenues per sh A	*44.50*
4.10	3.96	1.53	3.34	3.24	5.09	2.65	3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	*5.30*	*5.85*	"Cash Flow" per sh	*6.90*
2.15	1.81	d.76	.81	.63	1.22	.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	*1.25*	*1.60*	Earnings per sh A B	*2.35*
1.39	1.40	.88	.70	.74	.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	*.82*	*.82*	Div'ds Decl'd per sh C■	*.82*
5.67	5.06	3.76	5.02	5.43	6.64	6.79	8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	*6.35*	*6.60*	Cap'l Spending per sh	*6.50*
17.30	17.63	15.88	15.99	15.96	16.38	14.55	14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	*20.15*	*20.80*	Book Value per sh	*23.55*
19.32	20.04	20.60	20.60	21.00	21.28	24.47	26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	*37.75*	*38.00*	Common Shs Outst'g D	*40.00*
8.5	8.7	--	16.6	26.5	14.0	NMF	NMF	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.64	.65	--	1.01	1.57	.92	NMF	NMF	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	*Value Line*		Relative P/E Ratio	*1.20*
7.6%	8.9%	7.0%	5.2%	4.4%	4.7%	5.4%	4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*1.9%*

CAPITAL STRUCTURE as of 3/31/05

Total Debt $1302.4 mill. Due in 5 Yrs $505.0 mill.
LT Debt $1262.1 mill. LT Interest $80.0 mill.
(Total interest coverage: 1.9x)

Pension Assets-12/04 $242.2 mill.
Oblig. $319.4 mill.

Pfd Stock None

Common Stock 37,617,317 shs.
(as of 5/3/05)

MARKET CAP: $950 million (Small Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
563.5	644.1	732.0	917.3	936.9	1034.1	1396.7	1320.9	1231.0	1477.1	*1610*	*1655*	Revenues ($mill) A	*1780*
2.7	6.6	20.8	47.5	39.3	38.3	37.2	38.6	38.5	58.9	*45.0*	*60.0*	Net Profit ($mill)	*95.0*
24.0%	37.1%	29.2%	43.4%	35.5%	26.2%	34.5%	32.8%	30.5%	34.8%	*35.0%*	*35.0%*	Income Tax Rate	*31.0%*
.5%	1.0%	2.8%	5.2%	4.2%	3.7%	2.7%	2.9%	3.1%	4.0%	*2.9%*	*3.7%*	Net Profit Margin	*5.3%*
65.2%	60.2%	63.6%	60.2%	60.3%	60.2%	56.2%	62.5%	66.0%	64.2%	*62.0%*	*60.5%*	Long-Term Debt Ratio	*51.5%*
34.8%	34.4%	31.5%	35.3%	35.5%	35.8%	39.6%	34.1%	34.0%	35.8%	*38.0%*	*39.5%*	Common Equity Ratio	*48.5%*
1024.0	1104.8	1224.7	1349.3	1424.7	1489.9	1417.6	1748.3	1851.6	1968.6	*2010*	*1990*	Total Capital ($mill) A	*1940*
1137.8	1278.5	1360.3	1459.4	1581.1	1686.1	1825.6	1979.5	2175.7	2336.0	*2535*	*2720*	Net Plant ($mill)	*3295*
2.7%	2.8%	3.9%	5.8%	4.8%	4.6%	5.1%	4.3%	4.2%	5.0%	*4.0%*	*5.0%*	Return on Total Cap'l	*7.0%*
.7%	1.5%	4.7%	8.9%	7.0%	6.5%	6.0%	5.9%	6.1%	8.3%	*6.0%*	*7.5%*	Return on Shr. Equity	*10.0%*
.7%	1.7%	5.4%	10.0%	7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	*6.0%*	*7.5%*	Return on Com Equity	*10.0%*
NMF	NMF	NMF	5.0%	2.8%	2.4%	1.9%	1.9%	1.7%	4.3%	*2.0%*	*3.5%*	Retained to Com Eq	*6.5%*
NMF	NMF	107%	50%	64%	67%	71%	70%	72%	49%	*69%*	*52%*	All Div'ds to Net Prof	*35%*

CURRENT POSITION ($MILL.)

	2003	2004	3/31/05
Cash Assets	17.2	13.6	16.7
Other	263.9	418.4	314.5
Current Assets	281.1	432.0	331.2
Accts Payable	110.1	165.9	103.1
Debt Due	58.4	129.8	40.3
Other	141.9	187.3	188.5
Current Liab.	310.4	483.0	331.9
Fix. Chg. Cov.	182%	166%	183%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	4.0%	6.0%	3.5%
"Cash Flow"	3.0%	4.5%	6.0%
Earnings	4.0%	1.5%	10.5%
Dividends	1.0%	--	1.5%
Book Value	1.5%	4.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	499.5	261.1	223.9	336.4	1320.9
2003	403.3	255.8	220.2	351.7	1231.0
2004	473.4	278.7	264.5	460.5	1477.1
2005	542.9	*315*	*295*	*457.1*	*1610*
2006	*560*	*330*	*310*	*455*	*1655*

Cal-endar	EARNINGS PER SHARE B E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1.14	d.35	d.49	.86	1.16
2003	.76	d.12	d.51	1.00	1.13
2004	1.18	d.24	d.51	1.23	1.66
2005	.88	*d.23*	*d.50*	*1.10*	*1.25*
2006	*1.05*	*d.20*	*d.45*	*1.20*	*1.60*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.205	.205	.205	.205	.82
2002	.205	.205	.205	.205	.82
2003	.205	.205	.205	.205	.82
2004	.205	.205	.205	.205	.82
2005	.205	.205			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approx. 1.6 million customers in sections of Arizona, Nevada, and California. '04 margin mix: resid. and small commercial, 83%; large commercial and industrial, 4%; transportation, 13%. Annual volume: 2.2 billion therms. Principal suppliers: El Paso Natural Gas Co. and Northwest Pipeline Corp. Acquired gas utility assets from Arizona Public Service in 1984. Sold PriMerit Bank (acq. in '86) in 7/96. Has about 2,550 employees, 22,990 shareholders. Officers & Directors own 1.8% of common (6/04 Proxy). Chairman.: Thomas Y. Hartley. CEO: Jeffrey W. Shaw. Incorporated: CA. Address: 5241 Spring Mountain Rd., P.O. Box 98510, Las Vegas, NV 89193-8510. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas had a much weaker-than-expected first-quarter. Share net of $0.88 was significantly below our estimate of $1.23. The company suffered from warmer weather in its service territories, particularly in its largest operating area, Arizona. Results remain sensitive to temperature fluctuations, given the absence of a *weather-normalization policy.* This, coupled with higher operating costs, which increased 6% over last year's comparable period, crimped the bottom line. Southwest's operating leverage is slim given the exorbitant maintenance costs implicit in supporting its higher-than-average customer growth rate, which stands at around 5% annually.

The company is awaiting a rate-case decision in Arizona, which would mitigate the impact of weather on earnings and allow the company to recover its higher costs—all of which should benefit earnings going forward. Importantly, without the change in rate design, we think that Southwest's return on equity will continue to lag that of its peers. As a result of the weak first quarter, we have lowered our 2005 earnings estimate by $0.45 a share, to $1.25. Notwithstanding a rate hike, the company will need more favorable temperatures over the balance of the year to generate meaningful bottom-line growth, in our view.

During the last twelve months, Southwest added a record 82,000 customers. Typically, this pace of customer growth, while impressive, has been a doubled-edged sword for the company, given the implicit costs associated with such rapid expansion.

Southwest shares are not a standout. The company's balance sheet remains fairly highly leveraged, which doesn't augur well as interest rates ratchet up. Plus, in addition to seasonal losses, earnings have faltered dramatically for the reasons outlined above. As such, the current valuation reflects the difficulty of translating customer growth into earnings. Furthermore, as an income vehicle, Southwest shares are unappealing, since the yield is below average for the group and dividend payments have not expanded in almost a decade. Investors may want to look elsewhere until earning stabilize.

Edward Plank *June 17, 2005*

(A) Incl. income for PriMerit Bank on the equity basis through 1994.
(B) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '93, 8¢; '97, 16¢; '02, (10¢). Incl. asset writedown: '86, 9¢; '93, 44¢. Excl. loss from disc. ops.: '95, 75¢. Next egs. report due late July.
(C) Dividends historically paid early March, June, September, December.
■ Div'd reinvest. plan avail. (D) In millions.
(E) Quarters may not sum due to change in shares outstanding.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	65

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-04-0876

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SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
COST OF CAPITAL SUMMARY

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 1

LINE NO.	DESCRIPTION	(A) CAPITAL RATIO	(B) COST	(C) WEIGHTED COST
1	LONG-TERM DEBT	53.00%	7.49%	3.97%
2	PREFERRED EQUITY	5.00%	8.20%	0.41%
3	COMMON EQUITY	42.00%	10.15%	4.26%
4	TOTAL CAPITALIZATION	100.00%		8.64%
5	COST OF CAPITAL			

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) ÷ COLUMN (C), LINE 4
COLUMN (E): TESTIMONY, WAR
COLUMN (F): COLUMN (D) x COLUMN (E)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DCF COST OF EQUITY CAPITAL

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	ATG	AGL RESOURCES, INC.	3.44%	+	6.22%	=	9.66%
2	CGC	CASCADE NATURAL GAS CORPORATION	4.86%	+	4.29%	=	9.15%
3	KSE	KEYSPAN CORP.	4.58%	+	4.49%	=	9.06%
4	LG	LACLEDE GROUP, INC.	4.55%	+	3.41%	=	7.96%
5	GAS	NICOR, INC.	4.66%	+	2.91%	=	7.57%
6	NWN	NORTHWEST NATURAL GAS CO.	3.53%	+	5.36%	=	8.89%
7	PGL	PEOPLES ENERGY CORPORATION	5.11%	+	3.73%	=	8.84%
8	PNY	PIEDMONT NATURAL GAS COMPANY	3.83%	+	4.14%	=	7.97%
9	SJI	SOUTH JERSEY INDUSTIES, INC.	2.90%	+	7.21%	=	10.11%
10	WGL	WGL HOLDINGS, INC.	4.07%	+	5.86%	=	9.93%
11	LOCAL DISTRIBUTION COMPANY AVERAGE						8.91%

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DIVIDEND YIELD CALCULATION

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	÷	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	ATG	AGL RESOURCES, INC.	$1.24	÷	$36.02	=	3.44%
2	CGC	CASCADE NATURAL GAS CORPORATION	0.96	÷	19.77	=	4.86%
3	KSE	KEYSPAN CORP.	1.82	÷	39.75	=	4.58%
4	LG	LACLEDE GROUP, INC.	1.38	÷	30.36	=	4.55%
5	GAS	NICOR, INC.	1.86	÷	39.94	=	4.66%
6	NWN	NORTHWEST NATURAL GAS CO.	1.30	÷	36.85	=	3.53%
7	PGL	PEOPLES ENERGY CORPORATION	2.18	÷	42.65	=	5.11%
8	PNY	PIEDMONT NATURAL GAS COMPANY	0.92	÷	24.03	=	3.83%
9	SJI	SOUTH JERSEY INDUSTIES, INC.	0.85	÷	29.23	=	2.90%
10	WGL	WGL HOLDINGS, INC.	1.33	÷	32.73	=	4.07%
11	LOCAL DISTRIBUTION COMPANY AVERAGE						4.15%

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - SUMMARY AND INDEX DATED 06/17/05.
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 05/09/05 TO 07/01/05 STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) ÷ COLUMN (B)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 4
PAGE 1 OF 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	ATG	AGL RESOURCES, INC.	6.00%	+	0.22%	=	6.22%
2	CGC	CASCADE NATURAL GAS CORPORATION	4.00%	+	0.29%	=	4.29%
3	KSE	KEYSPAN CORP.	4.00%	+	0.49%	=	4.49%
4	LG	LACLEDE GROUP, INC.	3.00%	+	0.41%	=	3.41%
5	GAS	NICOR, INC.	2.75%	+	0.16%	=	2.91%
6	NWN	NORTHWEST NATURAL GAS CO.	5.00%	+	0.36%	=	5.36%
7	PGL	PEOPLES ENERGY CORPORATION	3.00%	+	0.73%	=	3.73%
8	PNY	PIEDMONT NATURAL GAS COMPANY	4.00%	+	0.14%	=	4.14%
9	SJI	SOUTH JERSEY INDUSTIES, INC.	6.00%	+	1.21%	=	7.21%
10	WGL	WGL HOLDINGS, INC.	5.75%	+	0.11%	=	5.86%
11	LOCAL DISTRIBUTION COMPANY AVERAGE						4.76%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 4

			(A)		(B)		(C)
LINE NO.	STOCK SYMBOL	COMPANY	SHARE GROWTH	x	{ [((M ÷ B) + 1) ÷ 2] - 1 }	=	EXTERNAL GROWTH (sv)
1	ATG	AGL RESOURCES, INC.	0.50%	x	{ [((1.89) + 1) ÷ 2] - 1 }	=	0.22%
2	CGC	CASCADE NATURAL GAS CORPORATIO	1.00%	x	{ [((1.59) + 1) ÷ 2] - 1 }	=	0.29%
3	KSE	KEYSPAN CORP.	2.00%	x	{ [((1.49) + 1) ÷ 2] - 1 }	=	0.49%
4	LG	LACLEDE GROUP, INC.	1.50%	x	{ [((1.55) + 1) ÷ 2] - 1 }	=	0.41%
5	GAS	NICOR, INC.	0.25%	x	{ [((2.31) + 1) ÷ 2] - 1 }	=	0.16%
6	NWN	NORTHWEST NATURAL GAS CO.	1.00%	x	{ [((1.72) + 1) ÷ 2] - 1 }	=	0.36%
7	PGL	PEOPLES ENERGY CORPORATION	1.75%	x	{ [((1.83) + 1) ÷ 2] - 1 }	=	0.73%
8	PNY	PIEDMONT NATURAL GAS COMPANY	0.25%	x	{ [((2.10) + 1) ÷ 2] - 1 }	=	0.14%
9	SJI	SOUTH JERSEY INDUSTIES, INC.	2.00%	x	{ [((2.21) + 1) ÷ 2] - 1 }	=	1.21%
10	WGL	WGL HOLDINGS, INC.	0.25%	x	{ [((1.86) + 1) ÷ 2] - 1 }	=	0.11%
11	LOCAL DISTRIBUTION COMPANY AVERAGE						

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY, 06/17/05

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	COMPANY	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	ATG	AGL RESOURCES, INC.	2000	0.1628		11.50%		1.87%	11.50	54.00	
2			2001	0.2800		12.30%		3.44%	12.19	55.10	
3			2002	0.4066		14.50%		5.90%	12.52	56.70	
4			2003	0.4663		14.00%		6.53%	14.66	64.50	
5			2004	0.4956		11.00%		5.45%	18.06	76.70	
6			GROWTH 2000 - 2004					4.64%	6.00%		9.17%
7			2005	0.4609		12.00%		5.53%		77.20	0.65%
8			2006	0.4708		12.00%		5.65%		77.50	0.52%
9			2008-10	0.5091		11.50%		5.85%	8.00%	78.00	0.34%
10											
11	CGC	CASCADE NATURAL GAS CORPORATION	2000	0.3094		12.90%		3.99%	10.79	11.05	
12			2001	0.3469		13.30%		4.61%	11.01	11.05	
13			2002	0.1504		10.90%		1.64%	10.34	11.05	
14			2003	-0.1034		8.60%		-0.89%	10.11	11.13	
15			2004	0.1933		11.20%		2.16%	10.52	11.27	
16			GROWTH 2000 - 2004					2.30%	-		0.49%
17			2005	-0.0105		7.50%		-0.08%		11.30	0.27%
18			2006	0.2320		9.00%		2.09%		11.30	0.13%
19			2008-10	0.3875		11.00%		4.26%	7.00%	12.00	1.26%
20											
21	KSE	KEYSPAN CORP.	2000	0.1524		10.00%		1.52%	20.65	136.36	
22			2001	-0.0349		8.20%		-0.29%	20.73	139.43	
23			2002	0.3527		13.30%		4.69%	20.67	142.42	
24			2003	0.3206		11.40%		3.65%	22.94	159.66	
25			2004	0.5265		15.60%		8.21%	24.22	160.82	
26			GROWTH 2000 - 2004					3.56%	1.50%		4.21%
27			2005	0.2375		9.00%		2.14%		170.00	5.71%
28			2006	0.2885		9.50%		2.74%		170.00	2.81%
29			2008-10	0.3846		10.50%		4.04%	5.00%	166.00	0.64%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/17/05
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2000 - 2004

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	COMPANY	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	LG	LACLEDE GROUP, INC.	2000	0.0219		9.10%		0.20%	14.99	18.88	
2			2001	0.1677		10.50%		1.76%	15.26	18.88	
3			2002	-0.1356		7.80%		NMF	15.07	18.96	
4			2003	0.2637		11.60%		3.06%	15.65	19.11	
5			2004	0.2582		10.10%		2.61%	16.96	20.98	
6			GROWTH 2000 - 2004					1.91%	1.50%		2.67%
7			2005	0.2171		9.00%		1.95%		21.50	2.48%
8			2006	0.2923		9.00%		2.63%		21.50	1.23%
9			2008-10	0.3689		8.00%		2.95%	11.00%	21.50	0.49%
10											
11	GAS	NICOR, INC.	2000	0.4354		19.20%		8.36%	15.56	45.49	
12			2001	0.4153		18.70%		7.77%	16.39	44.40	
13			2002	0.3611		17.50%		6.32%	16.55	44.01	
14			2003	0.1185		12.30%		1.46%	17.13	44.04	
15			2004	0.1622		13.10%		2.12%	16.99	44.10	
16			GROWTH 2000 - 2004					5.21%	1.00%		-0.77%
17			2005	0.1143		12.50%		1.43%		44.20	0.23%
18			2006	0.1733		12.50%		2.17%		44.20	0.11%
19			2008-10	0.2078		13.50%		2.81%	2.00%	44.50	0.18%
20											
21	NWN	NORTHWEST NATURAL GAS CO.	2000	0.3073		10.00%		3.07%	17.93	25.23	
22			2001	0.3351		10.20%		3.42%	18.56	25.23	
23			2002	0.2222		8.50%		1.89%	18.88	25.59	
24			2003	0.2784		9.00%		2.51%	19.52	25.94	
25			2004	0.3011		8.90%		2.68%	20.64	27.55	
26			GROWTH 2000 - 2004					2.71%	3.50%		2.22%
27			2005	0.4217		10.50%		4.43%		27.75	0.73%
28			2006	0.4333		10.50%		4.55%		28.00	0.81%
29			2008-10	0.4444		10.50%		4.67%	4.50%	28.50	0.68%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/17/05
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2000 - 2004

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	COMPANY	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	PGL	PEOPLES ENERGY CORPORATION	2000	0.2620		12.40%		3.25%	22.02	35.30	
2			2001	0.3544		13.90%		4.93%	22.76	35.40	
3			2002	0.2607		12.30%		3.21%	22.74	35.46	
4			2003	0.2613		12.30%		3.21%	23.11	36.69	
5			2004	0.0092		9.40%		0.09%	23.06	36.69	
6			GROWTH 2000 - 2004					2.94%	2.50%		0.97%
7			2005	0.1615		11.50%		1.86%		38.00	3.57%
8			2006	0.1852		11.50%		2.13%		38.00	1.77%
9			2008-10	0.2750		10.50%		2.89%	4.50%	35.00	-0.94%
10											
11	PNY	PIEDMONT NATURAL GAS COMPANY	2000	0.2871		12.10%		3.47%	8.26	63.83	
12			2001	0.2475		12.10%		3.00%	8.63	64.93	
13			2002	0.1579		10.60%		1.67%	8.91	66.18	
14			2003	0.2613		11.80%		3.08%	9.36	67.31	
15			2004	0.3228		11.10%		3.58%	11.15	76.67	
16			GROWTH 2000 - 2004					2.96%	5.50%		4.69%
17			2005	0.2640		11.00%		2.90%		77.00	0.43%
18			2006	0.2462		11.00%		2.71%		76.00	-0.44%
19			2008-10	0.3125		12.00%		3.75%	7.50%	73.00	-0.98%
20											
21	SJI	SOUTH JERSEY INDUSTIES, INC.	2000	0.3241		14.80%		4.80%	7.25	23.00	
22			2001	0.3565		14.80%		5.28%	7.81	23.72	
23			2002	0.3852		12.50%		4.82%	9.67	24.41	
24			2003	0.4307		11.60%		5.00%	11.26	26.46	
25			2004	0.4810		12.50%		6.01%	12.41	27.76	
26			GROWTH 2000 - 2004					5.18%	11.50%		4.81%
27			2005	0.4848		13.00%		6.30%		28.40	2.31%
28			2006	0.4857		12.50%		6.07%		28.60	1.50%
29			2008-10	0.4250		12.50%		5.31%	6.00%	30.00	1.56%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/17/05
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2000 - 2004

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	COMPANY	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	WGL	WGL HOLDINGS, INC.	2000	0.3073		11.70%		3.59%	15.31	46.47	
2			2001	0.3298		11.70%		3.86%	16.24	48.54	
3			2002	-0.1140		7.20%		NMF	15.78	48.56	
4			2003	0.4435		14.00%		6.21%	16.25	48.63	
5			2004	0.3434		11.70%		4.02%	16.95	48.67	
6			GROWTH 2000 - 2004					4.42%	3.00%		1.16%
7			2005	0.3350		11.00%		3.69%		48.70	0.06%
8			2006	0.3619		11.00%		3.98%		48.70	0.03%
9			2008-10	0.4615		12.50%		5.77%	4.00%	48.70	0.01%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/17/05
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINE 6, SIMPLE AVERAGE GROWTH, 2000 - 2004

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINE 6, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
GROWTH RATE COMPARISON

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 6

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) DPS	(C) BVPS	(D) VALUE LINE HISTORIC EPS	(D) DPS	(D) BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) DPS	(F) BVPS
1	ATG	6.22%	6.00%	5.00%	3.50%	8.00%	11.00%	0.50%	6.00%	5.71%	15.30%	1.58%	11.95%
2	CGC	4.29%	4.10%	7.00%	0.50%	7.00%	1.00%	-	-	3.92%	-3.81%	0.00%	-0.63%
3	KSE	4.49%	9.40%	1.00%	2.00%	5.00%	21.00%	4.00%	1.50%	6.27%	15.83%	0.14%	4.07%
4	LG	3.41%	3.50%	6.00%	1.00%	11.00%	-0.50%	0.50%	1.50%	3.29%	7.36%	0.19%	3.13%
5	GAS	2.91%	6.30%	1.00%	1.50%	2.00%	-0.50%	4.50%	1.00%	2.26%	-6.78%	2.88%	2.22%
6	NWN	5.36%	5.80%	7.50%	2.50%	4.50%	3.00%	1.00%	3.50%	3.97%	0.96%	1.19%	3.58%
7	PGL	3.73%	6.30%	1.00%	1.50%	4.50%	2.00%	2.00%	2.50%	2.83%	-5.30%	1.94%	1.16%
8	PNY	4.14%	6.70%	7.50%	4.00%	7.50%	3.00%	5.00%	5.50%	5.60%	5.89%	4.54%	7.79%
9	SJI	7.21%	5.30%	5.50%	5.00%	6.00%	10.50%	1.50%	11.50%	6.47%	9.98%	2.95%	14.38%
10	WGL	5.86%	5.30%	6.50%	1.50%	4.00%	2.00%	1.50%	3.00%	3.40%	2.55%	1.19%	2.58%
11				4.80%	2.30%	5.95%	5.25%	2.28%	4.00%		4.20%	1.66%	5.02%
12	AVERAGES	4.76%	5.87%		4.35%			3.84%		4.37%		3.63%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 06/17/05
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 06/17/05
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1, 3, 5 AND 7
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM
- VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 06/17/05

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
CAPM COST OF EQUITY CAPITAL

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 7

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ATG	k	=	3.04%	+ [	0.85	x	(	10.40%	-	3.04%	)]	=	9.30%
2	CGC	k	=	3.04%	+ [	0.75	x	(	10.40%	-	3.04%	)]	=	8.56%
3	KSE	k	=	3.04%	+ [	0.80	x	(	10.40%	-	3.04%	)]	=	8.93%
4	LG	k	=	3.04%	+ [	0.75	x	(	10.40%	-	3.04%	)]	=	8.56%
5	GAS	k	=	3.04%	+ [	1.10	x	(	10.40%	-	3.04%	)]	=	11.14%
6	NWN	k	=	3.04%	+ [	0.70	x	(	10.40%	-	3.04%	)]	=	8.19%
7	PGL	k	=	3.04%	+ [	0.80	x	(	10.40%	-	3.04%	)]	=	8.93%
8	PNY	k	=	3.04%	+ [	0.75	x	(	10.40%	-	3.04%	)]	=	8.56%
9	SJI	k	=	3.04%	+ [	0.60	x	(	10.40%	-	3.04%	)]	=	7.45%
10	WGL	k	=	3.04%	+ [	0.75	x	(	10.40%	-	3.04%	)]	=	8.56%
11	LDC AVERAGE					0.79								8.82%

REFERENCES:
COLUMN (A): GENERAL CAPITAL ASSET PRICING MODEL (CAPM) FORMULA

$$k = r_f + [\,ß\,(r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 06/10/05 THROUGH 07/15/05 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2004 PERIOD. THE DATA WAS OBTAINED FROM IBBOTSON ASSOCIATES' STOCKS, BONDS, BILLS AND INFLATION: 2005 YEARBOOK.

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
CAPM COST OF EQUITY CAPITAL

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 7
PAGE 2 OF 2

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ATG	k	=	3.04%	+ [	0.85	x	(	12.40%	-	3.04%	)]	=	11.00%
2	CGC	k	=	3.04%	+ [	0.75	x	(	12.40%	-	3.04%	)]	=	10.06%
3	KSE	k	=	3.04%	+ [	0.80	x	(	12.40%	-	3.04%	)]	=	10.53%
4	LG	k	=	3.04%	+ [	0.75	x	(	12.40%	-	3.04%	)]	=	10.06%
5	GAS	k	=	3.04%	+ [	1.10	x	(	12.40%	-	3.04%	)]	=	13.34%
6	NWN	k	=	3.04%	+ [	0.70	x	(	12.40%	-	3.04%	)]	=	9.59%
7	PGL	k	=	3.04%	+ [	0.80	x	(	12.40%	-	3.04%	)]	=	10.53%
8	PNY	k	=	3.04%	+ [	0.75	x	(	12.40%	-	3.04%	)]	=	10.06%
9	SJI	k	=	3.04%	+ [	0.60	x	(	12.40%	-	3.04%	)]	=	8.65%
10	WGL	k	=	3.04%	+ [	0.75	x	(	12.40%	-	3.04%	)]	=	10.06%
11	LDC AVERAGE					0.79								10.39%

REFERENCES:
COLUMN (A): GENERAL CAPITAL ASSET PRICING MODEL (CAPM) FORMULA

$k = r_f + [ß (r_m - r_f)]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 06/10/05 THROUGH 07/15/05 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2004 PERIOD. THE DATA WAS OBTAINED FROM IBBOTSON ASSOCIATES' STOCKS, BONDS, BILLS AND INFLATION: 2005 YEARBOOK.

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 8

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.40%	1.90%	10.01%	6.98%	8.10%	7.49%	8.61%	9.86%	10.06%
2	1991	4.21%	-0.20%	8.46%	5.45%	5.69%	5.38%	8.14%	9.36%	9.55%
3	1992	3.01%	3.30%	6.25%	3.25%	3.52%	3.43%	7.67%	8.69%	8.86%
4	1993	2.99%	2.70%	6.00%	3.00%	3.02%	3.00%	6.60%	7.59%	7.91%
5	1994	2.56%	4.00%	7.14%	3.60%	4.20%	4.25%	7.37%	8.31%	8.63%
6	1995	2.83%	2.50%	8.83%	5.21%	5.84%	5.49%	6.88%	7.89%	8.29%
7	1996	2.95%	3.70%	8.27%	5.02%	5.30%	5.01%	6.70%	7.75%	8.17%
8	1997	1.70%	4.50%	8.44%	5.00%	5.46%	5.06%	6.61%	7.60%	8.12%
9	1998	1.60%	4.20%	8.35%	4.92%	5.35%	4.78%	5.58%	7.04%	7.27%
10	1999	2.70%	4.50%	7.99%	4.62%	4.97%	4.64%	5.86%	7.62%	7.88%
11	2000	3.40%	3.70%	9.23%	5.73%	6.24%	5.82%	5.94%	8.24%	8.36%
12	2001	1.60%	0.80%	6.92%	3.41%	3.88%	3.38%	5.95%	7.59%	8.02%
13	2002	2.40%	1.90%	4.67%	1.17%	1.66%	1.60%	5.38%	7.41%	7.98%
14	2003	1.90%	3.00%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	2.23%	4.40%	4.34%	2.35%	1.35%	1.37%	5.03%	5.77%	6.20%
16	CURRENT	2.80%	3.50%	6.25%	4.25%	3.25%	3.14%	4.32%	5.18%	5.56%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 07/15/05
COLUMN (H) THROUGH (J): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2002 THROUGH 2004 THE VALUE LINE INVESTMENT SURVEY

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
CAPITAL STRUCTURES OF PUBLICLY TRADED LDC's (IN MILLIONS)

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 9

LINE NO.		ATG	PCT.	CGC	PCT.	KSE	PCT.	LG	PCT.
1	SHORT-TERM DEBT	$0.0	0.0%	$0.0	0.0%	$0.0	0.0%	$0.0	0.0%
2	LONG-TERM DEBT	1,957.0	58.6%	176.4	59.8%	4,418.7	53.0%	380.3	51.6%
3	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	19.7	0.2%	1.1	0.1%
4	COMMON EQUITY	1,385.0	41.4%	118.5	40.2%	3,894.7	46.7%	355.9	48.3%
5	TOTALS	$3,342.0	100%	$294.9	100%	$8,333.1	100%	$737.3	100%
6		GAS	PCT.	NWN	PCT.	PGL	PCT.	PNY	PCT.
7	SHORT-TERM DEBT	$0.0	0.0%	$0.0	0.0%	$0.0	0.0%	$0.0	0.0%
8	LONG-TERM DEBT	495.3	39.8%	568.5	54.0%	897.4	50.8%	660.0	43.6%
9	PREFERRED STOCK	1.6	0.1%	0.0	0.0%	0.0	0.0%	0.0	0.0%
10	COMMON EQUITY	749.1	60.1%	484.0	46.0%	870.1	49.2%	854.9	56.4%
11	TOTALS	$1,246.0	100%	$1,052.5	100%	$1,767.5	100%	$1,514.9	100%
12		SJI	PCT.	WGL	PCT.	**AVERAGE**	**PCT.**	SWX	PCT.
13	SHORT-TERM DEBT	$0.0	0.0%	$0.0	0.0%	**$0.0**	**0.0%**	$0.0	0.0%
14	LONG-TERM DEBT	328.9	48.7%	590.2	40.1%	**1,047.3**	**51.2%**	1,181.4	60.8%
15	PREFERRED STOCK	1.7	0.3%	28.1	1.9%	**5.2**	**0.3%**	100.0	5.1%
16	COMMON EQUITY	344.4	51.0%	853.4	58.0%	**991.0**	**48.5%**	663.0	34.1%
17	TOTALS	$675.0	100%	$1,471.7	100%	**$2,043.5**	**100%**	$1,944.4	100%

REFERENCE:
2004 SEC 10-K FILINGS
COMPANY WITNESS WOOD EXHIBIT NO._(TKW-1)

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-04-0876

SURREBUTTAL TESTIMONY

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

SEPTEMBER 13, 2005

Admitted

EXHIBIT

tabbies

RUCO 2

10/04/05

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes, on July 26, 2005, I filed direct testimony with the Arizona Corporation Commission ("ACC" or "Commission"). My direct testimony addressed the cost of capital issues that were raised in Southwest Gas Corporation's ("SWG" or "Company") application requesting a permanent rate increase ("Application") based on a test year ended August 31, 2004 ("Test Year") and presented RUCO's recommended hypothetical capital structure in addition to RUCO's recommended returns on long-term debt and equity.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to respond to SWG's rebuttal testimony on RUCO's recommended rate of return on invested capital (which includes RUCO's recommended cost of debt, cost of preferred equity and cost of common equity) for the Company's natural gas distribution operations in Arizona.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony contains four parts: the introduction that I have just presented; a summary of SWG's rebuttal testimony; a section on the capital structure and cost of debt issues associated with the case; and a section on the cost of equity capital issues associated with the case.

SUMMARY OF SOUTHWEST GAS' REBUTTAL TESTIMONY

Q. Have you reviewed the rebuttal testimony of Company witnesses Theodore K. Wood and Frank J. Hanley?

A. Yes. I have reviewed the rebuttal testimony, on cost of capital issues, filed by the aforementioned Company witnesses on August 23, 2005.

Q. Please summarize the testimony filed by Company witness Wood.

A. Mr. Wood's rebuttal testimony largely concentrates on the hypothetical capital structures recommended by the Company, ACC Staff cost of capital consultant Stephen G. Hill and myself. Mr. Wood also compares and comments on the overall rate of return recommendations being made by the Company, ACC Staff and RUCO. Mr. Wood also takes issue with the cost of common equity being recommended by Mr. Hill and myself stating that our respective recommended costs of common equity of 9.50 percent and 10.15 percent are too low.

Q. Please summarize the testimony filed by Company witness Hanley.

A. Mr. Hanley's rebuttal testimony focuses entirely on the cost of common equity recommendations of ACC Staff and RUCO. Mr. Hanley is critical of Mr. Hill and myself on our reliance on the discounted cash flow ("DCF") model and the manner in which Mr. Hill and myself arrived at our DCF growth estimates. This includes our reliance on the assumption that a utility's market to book ratio will move in the direction of 1.0 if regulators set a utility's rate of return at a level that is equal to the utility's cost of capital and our reliance on the sustainable growth concept that is expressed in the growth component of the DCF model. Mr. Hanley also takes issue with the inputs used in Mr. Hill's and my capital asset pricing model ("CAPM") analyses and the use of a geometric mean in the calculation of the return on the market. Mr. Hanley is also critical of the position that both ACC Staff and RUCO have taken in regard to the Company-proposed conservation margin tracker ("CMT") mechanism.

CAPITAL STRUCTURE AND WEIGHTED COST OF DEBT

Q. Has RUCO made any changes to its recommended hypothetical capital structure based on the rebuttal testimony of Mr. Wood or the direct testimony of Mr. Hill?

A. No. RUCO has not made any changes to its recommended hypothetical capital structure.

Q. Briefly summarize the positions of the parties in the case in regard to capital structure.

A. Both RUCO and the Company are recommending identical hypothetical capital structures comprised of 53 percent debt, 5 percent preferred equity and 42 percent common equity. RUCO and the Company are also in agreement on the costs of debt and preferred equity (i.e. 7.49 percent and 8.20 percent respectively).

ACC Staff consultant Hill is recommending a slightly different hypothetical structure comprised of 55 percent debt, 5 percent preferred equity, and 40 percent common equity. Mr. Hill is in agreement with both RUCO and SWG in regard to his recommended cost of preferred equity of 8.20 percent but is recommending a slightly higher (by 12 basis points) weighted cost of debt of 7.61percent.

Q. What is the reason for the difference in the 7.61 percent weighted cost of debt being recommended by Mr. Hill and the 7.49 percent weighted cost of debt that you and the Company are recommending?

A. Mr. Hill obtained his weighted cost of debt from information provided in data request Staff-SH-12-2. His recommended 7.61 percent weighted cost of debt was derived from the levels of SWG debt that existed on March 31, 2005, and is comprised of $679,050,093 in fixed rate debt with an effective cost rate of 8.20 percent and a term facility of $99,371,603 with an effective rate of 3.54 percent. Based on information contained in data request Staff-SH-12-1, the Company's and my 7.49 percent weighted cost of debt is based on levels of SWG debt that existed as late as September 30, 2004 (one month after the Test Year), and was comprised of $679,050,093 in fixed rate debt with an effective cost rate of 8.20 percent and a term facility of $99,365,265 with an effective rate of 2.63 percent.

Q. Why have you decided not to make any changes to your recommended cost of debt?

A. My recommended 7.49 percent cost of debt is more representative of the level of debt that was used to finance the Company's assets that were booked at the end of the Test Year (i.e. August 31, 2004).

Q. What would the Company's weighted cost of capital be if your recommended cost of debt and common equity were substituted into Mr. Hill's recommended capital structure?

A. Substituting my recommended costs of debt and common equity into Mr. Hill's recommended hypothetical capital structure would produce a weighted cost of capital of 8.59 percent which is 5 basis points lower than my recommended 8.64 percent cost of common equity, 81 basis points lower than the 9.40 percent Company-proposed weighted cost of capital, and 19 basis points higher than Mr. Hill's recommended 8.40 percent weighted cost of capital.

Q. What would the Company's weighted cost of capital be if Mr. Hill's recommended cost of debt and common equity were substituted into the capital structure being recommended by you and the Company?

A. Substituting Mr. Hill's recommended costs of debt and common equity into the hypothetical capital structure being recommended by both RUCO and the Company would produce a weighted cost of capital of 8.43 percent which is 21 basis points lower than my recommended 8.64 percent cost of common equity, 97 basis points lower than the 9.40 percent Company-proposed weighted cost of capital, and 3 basis points higher than Mr. Hill's recommended 8.40 percent weighted cost of capital.

COST OF EQUITY CAPITAL

Q. Has RUCO made any changes to its recommended cost of common equity based on the rebuttal testimony of Mr. Hanley or the direct testimony of Mr. Hill?

A. No. RUCO is still recommending the same 10.15 percent cost of common equity that I recommended in my direct testimony.

...

Q. Briefly summarize the positions of the Company and ACC Staff in regard to the cost of common equity.

A. The Company is still proposing an 11.95 percent cost of common equity (contingent on the Commission's decision on the Company-proposed CMT), that is 180 basis points higher than my recommended 10.15 percent cost of common equity. ACC Staff is recommending a 9.50 percent cost of common equity that is 240 basis points lower than the 11.95 percent cost of common equity proposed by the Company and 65 basis points lower than my 10.15 percent estimate.

Q. What cost of common equity would result if you relied solely on an average of your DCF and CAPM results?

A. An average of my DCF and CAPM results (using both an arithmetic and a geometric mean) results in a cost of common equity of 9.38 percent, which is 12 basis points lower than Mr. Hill's 9.50 percent recommendation and 257 basis points lower than Mr. Hanley's 11.95 percent estimate (contingent on the Commission's decision on the Company-proposed CMT).

...

Q. Please respond to Mr. Wood and Mr. Hanley's rebuttal positions that your recommended cost of equity is too low.

A. Based on the information presented in both Mr. Hill's and my direct testimony I would have to say that just the opposite is true. Mr. Hanley's 11.95 percent recommendation, which, as I described on pages 48 through 55 of my direct testimony, was derived from a series of upward adjustments in virtually every step of his analysis, is unrealistically high for a regulated utility such as SWG.

Q. Please address Mr. Hanley's criticism of your DCF analysis, which takes into consideration the concept that a utility's market-to-book ratio will move toward a value of 1.0 if regulators set a utility's rate of return at a level that is equal to its cost of capital.

A. The lynchpin in Mr. Hanley's argument appears on page 7, line 16 of his rebuttal testimony where he states the following: "In the competitive, unregulated sector (and the natural gas industry is becoming increasingly competitive), there is no evidence of any direct relationship between market-to-book ratios and the rates of earnings on book common equity." Although Mr. Hanley wants to believe that SWG belongs in the same category as the unregulated competitive industries that Mr. Hanley refers to, the plain simple fact is that the Company is not in the same league. SWG is, for all practical purposes, a regulated utility that earns on the value of its rate base. This is a fact that the investment community has been aware of for many years and still accepts today. As I pointed out, through a quote from The Value Line Investment Survey ("Value Line") on page 41 of my direct testimony, the attraction of local distribution companies ("LDC") such as SWG, are the dividends they pay out as opposed to the capital appreciation of their stock. In this respect, investors view utility stocks in much the same way that they view corporate bonds.

Q. Why do you believe that SWG has little in common with firms that operate in a competitive environment?

A. I believe that SWG and the other LDC's included in my sample have operating characteristics that are actually closer to regulated water companies (which Value Line's analysts have described as the last pure monopolies). Both types of utilities have regulated rates and similar rate designs composed of fixed monthly minimum charges and commodity charges based on consumption. In addition, both types of utilities are largely distribution companies that serve relatively stable customer bases. In fact an argument could be made that LDC's bear less risk since their cost of gas is recovered through adjustor mechanisms as opposed to the majority of water providers that have no such mechanisms for their sources of supply. Furthermore, both types of utilities face similar conservation issues, which RUCO has addressed in this case through its recommended rate design.

Q. Please explain why you believe that the market value of a utility's stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital of firms with similar risk.

A. A utility's market price should equal its book price over the long run if regulators allow a rate of return that is equal to the utility's cost of capital. *That is assuming that the utility's rate of return ("ROR") is comparable to the rates of return of other firms in the same risk class.*[1] For example, if a hypothetical utility's book price is $20.00 per share and regulators adopt a rate of return that is equal to the utility's cost of capital of 10.00%, the utility will earn $2.00 per share ("EPS"). With earnings of $2.00 per share, and a market required rate of return on equity of 10.00%, for firms in the utility's risk class, the market price of the utility's stock will set at $20.00 per share ($2.00 EPS ÷ 10.00% ROR = $20.00 per share price). If the utility records earnings that are higher than the earnings of other firms with similar risk, the market value of the utility's shares will increase accordingly ($2.50 EPS ÷ 10.00% ROR = $25.00 per share). On the other hand, if the utility posts lower earnings, the stock's market price will fall below book value ($1.50 EPS ÷ 10.00% ROR = $15.00 per share).

Because of economic forces beyond the control of regulators, it is not reasonable to assume that the utility will have earnings that match those of firms of similar risk in every year of operation. In some years, earnings

[1] An in-depth discussion of why a market-to-book ratio of 1.0 is a desired long-term effect of regulation can be found in Roger A. Morin's text Regulatory Finance, Utilities' Cost of Capital.

may drop causing the market-to-book ratio to fall below 1.0, while in other years the utility may have earnings that exceed those of other firms in its risk classification. However, over the long run the utility's earnings should average out to the earnings that are expected based on its level of risk. These average earnings over time will result in a market-to-book ratio of 1.0. It has been suggested that regulators should set a utility's rate of return at a level that is slightly higher than that of firms in the same risk class of the hypothetical utility. In theory, this will send a message to investors that average long-term earnings will not be less than what is expected. A 1.0 ratio may never be achieved in practice and many investors may not even care what the market-to-book ratio is as long as they receive their required rate of return. As I noted earlier, in this respect, a utility stock is similar to a corporate bond whose value fluctuates as interest rates move above or below the stated yield on the bond. As long as the bond provides the level of income (i.e. the stated interest payment in the case of a bond or a dividend payment in the case of a utility stock) that the investor expects, the price of the instrument at any given point in time is immaterial (so long as the intent is to hold the bond until maturity or the utility stock over a long-term period).

...

Q. Does your recommended cost of equity take into consideration the theoretical concepts that you have just described?

A. Yes. As I just explained, in theory, a market-to-book ratio of 1.0 would be achieved if a utility's rate of return equaled the cost of capital that is close to the returns of firms with similar risk. My CAPM analysis, which determined an expected rate of return based on SWG's risk characteristics, indicates that the rate of return for a firm with SWG's level of risk should range from 8.82% (using a geometric mean) to 10.39% (using an arithmetic mean). Thus, my recommended cost of equity of 10.15% (which is 124 basis points higher than the result of my DCF analysis) is higher than the rate of return that would theoretically produce a market price that is equal to book value. Despite Mr. Hanley's argument to the contrary (on page 13 of his rebuttal testimony), it is only logical that the expectation that a utility's market-to-book ratio will move toward 1.0 should be incorporated into the DCF model as Mr. Hill and myself have done.

Q. Do you agree with Mr. Hanley's statement that your DCF results understates the cost rate to SWG because it was derived from LDC's that are not as risky as SWG?

A. No. A quick review of my direct testimony schedule WAR-7 will demonstrate that my DCF sample was actually riskier than SWG in terms of beta. My sample of LDC's had an average beta coefficient of 0.79 as opposed to SWG's beta of 0.75. This being the case, an argument could be made that my final estimate of 10.15 percent, which also takes into consideration the company's higher level of debt, is probably a little on the high side.

Q. Please respond to Mr. Hanley's position that both you and Mr. Hill place undue emphasis on the sustainable growth estimate (g = br + vs) component of the DCF model.

A. Once again, as evidenced on page 11 of his rebuttal testimony, Mr. Hanley's argument hinges on his belief that SWG has more in common with firms that operate in a competitive environment as opposed to being the regulated utility that it is. In short, Mr. Hanley believes that the future growth estimates of securities analysts should simply be plugged into equity valuation models (such as the DCF and CAPM) as opposed to conducting the type of critical analysis that Mr. Hill and I have performed which takes both historical results and future estimates into consideration.

Q. What is your response to Mr. Hanley's position that the yields on longer-term instruments should be used as the risk free rate of return component of the CAPM model as opposed to the average return on a 91-day Treasury Bill that you used?

A. Even though an ongoing debate exists in the academic community over what type of financial instrument best fits the definition of a risk free asset, I believe that the consistent use of a normalized 91-day Treasury Bill ("T-Bill") rate is the most theoretically sound instrument for use in the CAPM model.

Q. In his rebuttal testimony, Mr. Hanley explains why he believes that the use of longer-term instruments should be used in the CAPM model. Can you explain why you believe the use of a 91-day T-Bill is more appropriate than longer-term instruments?

A. Both Mr. Hill and myself believe that the use of the 91-day T-bill is justified for two reasons. First, investors face no maturity risk with the purchase of the 91-day T-Bill. As stated in my direct testimony, longer-term U.S. Treasury instruments, such as the forecasted long-term yield used by Mr. Hanley in his restatement, have higher yields due to maturity risk. These higher yields compensate investors for forgone future investment opportunities and for future unexpected changes in the rate of inflation. Mr. Hanley fails to recognize the fact that individuals who invest in 91-day T-bills do not face these risks. Unlike Mr. Hanley, I believe that a valid argument can be made that when maturity risk is taken into consideration, the yields on 91-day T-Bills emerge as a better proxy for the risk free rate of return that is an integral component of the CAPM.

Second, I believe, as does Mr. Hill, that the use of longer-term treasury instruments conflicts with the CAPM model's exclusive reliance on systematic risk. Systematic risk (also referred to as market risk) is defined as that part of a security's risk that is common to all securities of the same general class. It is risk that cannot be eliminated by diversification (the beta coefficient used in the CAPM is the measurement of systematic risk). CAPM theory asserts that the degree of systematic risk that is inherent in any stock, or investment portfolio, is captured by, and reflected in, the beta coefficient. A contributor to overall systematic risk is the risk of unexpected changes in the long-term inflation rate. Since the risk associated with unexpected changes in the long-term inflation rate is already included in the beta coefficient, the use of longer-term U.S. Treasury instruments as a risk free asset accounts for this risk twice – once with the beta and once with the long-term U.S. Treasury instrument yield. In short, I believe that the use of longer-term U.S. Treasury instruments in the CAPM model incorrectly double counts the long-term inflation return requirements of investors and produces overstated results.

Q. Are there other comments you want to make regarding the proper risk-free instrument that should be used in the CAPM?

A. Yes. At this particular point in time, Mr. Hanley's argument on this matter may well be moot. As I discussed in my direct testimony, the yield curve (exhibited in Attachment 1) that charts the yields of various U.S. Treasury securities has been flattening out over the last twelve-month period. As the Federal Reserve has been increasing the yields on short-tern instruments, such as the 91-day T-Bill that I used as the risk free rate of return in my CAPM model, the yields on long-term instruments, such as the 10-year instrument advocated by Mr. Hanley, have been falling. This being the case, the 91-day T-bill rate used in my analyses may well be a better predictor of what the risk free rate is and what an expected return on common equity should be for SWG.

Q. Please explain why Mr. Hanley's criticism regarding the use of a geometric mean in your CAPM analysis is unfounded.

A. As I stated in my direct testimony there is an on-going debate as to which is the better average to rely on. The best argument in favor of the geometric mean is that it provides a truer picture of the effects of compounding on the value of an investment when return variability exists. This is particularly relevant in the case of the return on the stock market, which has had its share of ups and downs over the 1926 to 2004 observation period used in my CAPM analysis.

The following example may help to illustrate the differences between the two averages. Suppose you invest $100 and realize a 20.0 percent return over the course of a year. So at the end of year 1, your original $100 investment is now worth $120. Now lets say that over the course of a second year you are not as fortunate and the value of your investment falls by 20.0 percent. As a result of this, the $120 value of your original

$100 investment falls to $96. An arithmetic mean of the return on your investment over the two-year period is zero percent calculated as follows:

$$(\text{year 1 return} + \text{year 2 return}) \div \text{number of periods} =$$

$$(20.0\% + -20.0\%) \div 2 =$$

$$(0.0\%) \div 2 = \underline{\underline{0.0\%}}$$

The arithmetic mean calculated above would lead you to believe that you didn't gain or lose anything over the two-year investment period, and that your original $100 investment is still worth $100. But in reality, your original $100 investment is only worth $96. A geometric mean on the other hand calculates a compound return of negative 2.02 percent as follows:

$$(\text{year 2 value} \div \text{original value})^{1/\text{number of periods}} - 1 =$$

$$(\$96 \div \$100)^{1/2} - 1 =$$

$$(0.96)^{1/2} - 1 =$$

$$(0.9798) - 1 =$$

$$-0.0202 = \underline{\underline{-2.02\%}}$$

So the geometric mean calculation illustrated above provides a truer picture of what happened to your original $100 over the two-year investment period.

As can be seen in the preceding example, in a situation where return variability exists, a geometric mean will always be lower than an arithmetic mean, which probably explains why utility consultants typically put up a strenuous argument against the use of a geometric mean. I have always used both averages for comparative purposes in my CAPM analyses, but have generally given the arithmetic average more weight in making a final cost of common equity estimate in order to err on the side of caution when making an estimate. In this case, my CAPM analysis using a geometric mean yielded a result of 8.82 percent, which was closer to my DCF result of 8.91 percent.

Q. Has any of Mr. Hanley's testimony on the ECAPM persuaded you to make any adjustments to your recommended cost of common equity?

A. No.

Q. Does your silence on any of the positions advocated by Mr. Wood or Mr. Hanley constitute your acceptance of them?

A. No, it does not.

Q. Does this conclude your surrebuttal testimony on SWG?

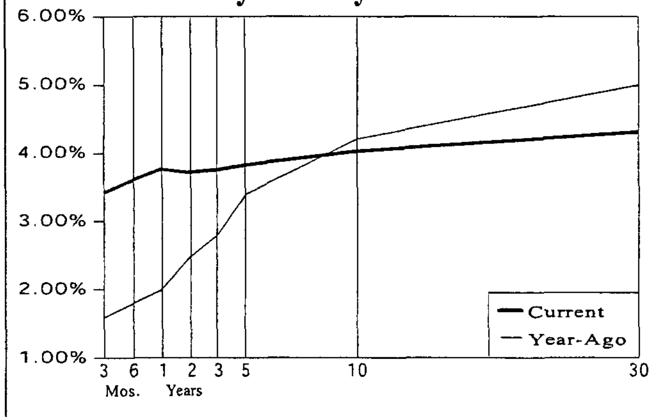
A. Yes, it does.

ATTACHMENT 1

Selected Yields

	Recent (9/01/05)	3 Months Ago (6/02/05)	Year Ago (9/02/04)
TAXABLE			
Market Rates			
Discount Rate	4.50	4.00	2.50
Fed Funds (Target)	3.50	3.00	1.50
Prime Rate	6.50	6.00	4.50
30-day CP (A1/P1)	3.56	3.00	1.52
3-month LIBOR	3.86	3.35	1.81
Bank CDs			
6-month	2.29	2.29	1.01
1-year	2.91	2.80	1.47
5-year	3.88	3.81	3.55
U.S. Treasury Securities			
3-month	3.42	2.97	1.59
6-month	3.60	3.13	1.79
1-year	3.77	3.25	1.99
5-year	3.83	3.66	3.39
10-year	4.03	3.90	4.21
10-year (inflation-protected)	1.54	1.52	1.83
30-year	4.31	4.24	5.00
30-year Zero	4.30	4.25	5.16

Treasury Security Yield Curve



	Recent (9/01/05)	3 Months Ago (6/02/05)	Year Ago (9/02/04)
Mortgage-Backed Securities			
GNMA 6.5%	5.00	4.79	4.43
FHLMC 6.5% (Gold)	5.44	4.99	4.41
FNMA 6.5%	4.97	4.76	4.39
FNMA ARM	3.88	3.58	2.78
Corporate Bonds			
Financial (10-year) A	4.92	4.71	5.16
Industrial (25/30-year) A	5.20	5.19	5.78
Utility (25/30-year) A	5.15	5.10	5.78
Utility (25/30-year) Baa/BBB	5.54	5.44	6.22
Foreign Bonds (10-Year)			
Canada	3.74	3.82	4.64
Germany	3.07	3.22	4.07
Japan	1.33	1.22	1.50
United Kingdom	4.12	4.24	4.97
Preferred Stocks			
Utility A	7.02	6.93	6.71
Financial A	6.08	6.02	5.98
Financial Adjustable A	5.53	5.42	5.39
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.18	4.18	4.63
25-Bond Index (Revs)	4.83	4.72	5.09
General Obligation Bonds (GOs)			
1-year Aaa	2.79	2.70	1.48
1-year A	2.91	2.87	1.63
5-year Aaa	3.09	2.93	2.63
5-year A	3.36	3.22	2.89
10-year Aaa	3.49	3.40	3.50
10-year A	3.81	3.74	3.84
25/30-year Aaa	4.22	4.21	4.70
25/30-year A	4.49	4.44	4.91
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.29	4.18	4.91
Electric AA	4.37	4.35	4.85
Housing AA	4.46	4.40	4.97
Hospital AA	4.44	4.40	5.20
Toll Road Aaa	4.40	4.34	4.94

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	8/31/05	**8/17/05**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1848	1325	523	1720	1678	1706
Borrowed Reserves	333	357	-24	335	216	188
Net Free/Borrowed Reserves	1515	968	547	1386	1463	1518

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	8/22/05	**8/15/05**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	1382.0	1355.4	26.6	1.6%	0.5%	1.1%
M2 (M1+savings+small time deposits)	6560.9	6536.6	24.3	4.8%	3.0%	3.8%
M3 (M2+large time deposits)	9898.3	9839.3	59.0	9.9%	7.4%	6.1%

EXHIBIT
tabbies
RUCO-3
Admitted

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-04-0876

DIRECT TESTIMONY

OF

MARYLEE DIAZ CORTEZ

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 26, 2005

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Marylee Diaz Cortez. I am a Certified Public Accountant. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office (RUCO) located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix I, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present recommendations resulting from my review and analysis of the Southwest Gas Corporation's (Company or SWG) application for an increase in gas rates.

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's application. My recommendations are based on these analyses. Procedures performed include the formulation and analysis of data requests, the review and analysis of Staff requested data, conversations with Company personnel, as well as a review of annual reports and prior ACC decisions.

Q. What areas will you address in your testimony?

A. I will address the revenue requirement issues of rate base, operating income, and rate design. RUCO witness Rodney Moore will also address rate base and operating income issues, as well as sponsor RUCO overall revenue requirement recommendation. RUCO witness William Rigsby will address the cost of capital. Collectively, the RUCO witnesses' testimony will support RUCO's overall recommended revenue requirement.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules MDC-1 through MDC-6.

Q. Please summarize the recommendations and adjustments you address in your testimony.

A. My testimony addresses the following issues:

<u>Rate Base</u>

<u>Pipe Replacements</u> - This adjustment writes off a percentage of the cost of replacing defective pipe as required by Decision No. 58698.

<u>Miscellaneous Intangible Plant</u> - This adjustment reflects the rate base effects of the Company-proposed expired software amortizations. The

adjustment removes from rate base plant and accumulated amortization of miscellaneous intangible plant that will expire by December 31, 2004.

Working Capital - This adjustment restates SWG's cash working capital requirement based RUCO's recommended level of operating expenses and lead/lag days. The adjustment also reclassifies certain test year expenses that produce a benefit equaling or exceeding one year to the Prepayments account.

Operating Income

Sarbanes Oxley Section 404 - This adjustment trues up the Company's estimated costs of complying with Section 404 of the Sarbanes Oxley Act of 2002 to actual costs.

Transmission Integrity Management Program (TRIMP) - This adjustment restates the estimated costs of implementing and maintaining the TRIMP based actual experience during 2004 and 2005.

Amortization of Miscellaneous Intangible Plant - This adjustment reduces test year amortization expense to reflect the level of Miscellaneous Intangible Plant recommended in Rate Base Adjustment #4.

Management Incentive Plan - This adjustment removes 67% of the cost of a bonus program that awards select employees for the achievement of certain goals. In large part the benefits of achieving these goals accrue solely to shareholders, particularly between rate cases.

Demand Side Management - RUCO recommends approval of SWG proposed ramp up in DSM spending, as well as outlines a recommended design and approval process.

Rate Design

Conservation Margin Tracker - RUCO recommends that the proposed CMT be denied and that less extreme rate design tools be used to address some of the Company's concerns, as well as establish fair and reasonable rates.

Rate Structure - This section outlines RUCO recommended rate structure.

RATE BASE

Rate Base Adjustment #2 - Pipe Replacement

Q. Please provide some background regarding SWG's pipe replacement program.

A. SWG, shortly after having purchased the gas distribution properties of Tucson Gas and Electric, determined that certain types of pipe[1] used in the system were defective. This defective pipe was an issue in several SWG rate cases in the 1980s and 1990s. The most recent Commission decision that addressed the defective pipe issue was Decision No. 58693, dated July 7, 1994. The decision was based on a settlement agreement by the parties, which among other things, resolved the issue of how the defective pipe would be treated for ratemaking purposes. SWG agreed to write off a certain annual percentage of the replacement cost of the

[1] Specifically, 1960's steel pipe, and plastic pipe known as Aldyl A, Aldyl HD, and ABS.

defective pipe types. The settlement agreement also provided that the pipe replacement percentage write off amounts would decline annually until the amount reached zero.

Q. Has Southwest Gas complied with the pipe replacement write off schedule as required by Decision No. 58693?

A. Yes. Up until the instant filing SWG has continued to make the required pipe replacement write offs. In this docket, however, the Company proposes to cease making some of the write offs required by Decision No. 58693.

Q. What is the Company's rationale for not making some of the required write offs?

A. The Company is requesting that the pipe write off schedule required by Decision No. 58693 be modified so that all pipe replacement write offs would cease when the specific type of pipe reached an average life of 40 years. Under SWG's proposal, both the 1960's steel pipe and the ABS pipe would no longer be subject to write off and the scheduled write offs for the Aldyl A and Aldyl HD pipe would be modified such that write offs would cease in 2013 and 2020, respectively.

Q. Do you agree with the Company proposed modifications to its scheduled pipe replacement cost write offs?

A. Yes, I believe modification of the Decision No. 58693 write off schedule is warranted since the schedule in its current form requires continued write offs of pipe replacement costs as far out as 2068. Clearly, if pipe lasts until 2068 before having to be replaced it cannot reasonably be argued that the pipe was defective, and therefore the replacement cost should not be disallowed.

Q. Have you accepted SWG proposed pipe replacement adjustment?

A. No. While I do not disagree with the modification of the scheduled write offs on a going forward basis I do disagree with applying the modification retroactively.

Q. Has the Company proposed to retroactively modify the write off schedule dictated by Decision No. 58693?

A. Yes, the Company's proposed adjustment would apply the modified write off schedule in the current docket to its 2000, 2001, 2003, and 2004 pipe replacements.

Q. Why is this wrong?

A. During the test year (2003/2004), as well as in previous years (2000 through 2002) the Company was required to abide by the terms set forth in Decision No. 58693, which requires these write offs. While the Company certainly is free to request a change in manner in which pipe replacement write offs are handled on a going forward basis, it cannot retroactively apply that proposed methodology to previous periods. Until superceded by a subsequent Commission decision that authorizes a different treatment for pipe replacement costs the Company must abide by the terms of Decision No. 58693 in this regard.

Q. What adjustment have you made?

A. As shown on Schedule MDC-1, I have recalculated the pipe replacement write offs utilizing the methodology required in Decision No. 58693. This adjustment decreases rate base $1,982,686.

Q. Do you agree with the Company's proposed modified pipe replacement write off methodology on a going forward basis?

A. Yes. I believe the Company has a valid argument that having to write off the cost of replacing pipe that has already outlived its useful life is inappropriate. RUCO supports the Company's modified pipe replacement schedule, based on a forty-year life, as set forth on Exhibit RAM-3 and recommends it be authorized on a going forward basis.

Rate Base Adjustment #4 - Miscellaneous Intangible Plant

Q. Has the Company proposed an adjustment to account 303 - Miscellaneous Intangible Plant?

A. Yes. Account 303 consists primarily of computer software and software development costs, that have relatively short amortization periods (typically five years or less). SWG has proposed an adjustment that removes all software amortization that expired during the test year and through December 31, 2004. The proposed adjustment also annualizes the amortization associated with new software costs that went into service during the test year and through December 31, 2004.

Q. Do you agree with this adjustment?

A. Yes. The test year changes in amortization expense are known and measurable and recognition of the expired, as well as the new, amortizations gives a better reflection of a going forward level of expense. The Company, however, has failed to reflect the impact on rate base of the expiring software.

Q. Please explain.

A. SWG's proposed adjustment merely removes the amortization *expense* associated with expired assets. It fails to recognize that when amortization expires, the associated asset has been fully recovered and is no longer entitled to rate base treatment.

Q. Are you recommending an adjustment that reflects the rate base impact of the Company's proposed account 303 expired amortization adjustment?

A. Yes. On Schedule MDC-2 I have removed the book value of the expiring account 303 assets from rate base. While the Company has increased rate base by the book value of new account 303 assets it failed to reduce rate base by the expired account 303 assets. This adjustment removes the expired assets from rate base and adjusts the Company's estimated cost of the new account 303 assets to actual costs. I have also removed the accumulated amortization balance associated with the expired account 303 assets. The adjustment results in a net decrease in rate base of $845,975.

Rate Base Adjustment #6 - Working Capital

Q. Have you reviewed the Company's requested level of working capital?

A. Yes. The Company is requesting $881,148 in working capital which is comprised of a cash working capital component (based on a lead/lag study), and 13-month average balances for SWG's prepayments and materials and supplies accounts.

Q. Do you agree with the methodology the Company has used to determine its working capital requirement?

A. Yes. First, the use of 13-month average balances for prepayments and materials and supplies is preferable to year-end balances because it smoothes out any month-to-month fluctuations in these account balances. Second, use of a lead/lag study, which measures the actual time elapsed between when goods and services are provided/received and when the cash is received/paid, renders the most accurate estimate of the amount of cash the Company must have on hand to operate the business.

Q. Do you agree with the amount of working capital the Company has requested?

A. No. I disagree with some the Company's lag day calculations, and I disagree with the 13-month average balance in the prepayments account. I will be proposing adjustments related to these items. Also my working capital calculations are based on RUCO's recommended level of operating expense, and for this reason render a different level of working capital than the Company.

Q. Please discuss your recommended lead/lag day adjustments.

A. I am recommending an adjustment to the Company's Income Tax lag calculation and to its Other O&M lag calculation. SWG has calculated its Income Tax lag as 37 days. The calculation is based on the assumption that 25% of SWG's annual income tax liability must be paid quarterly on April 15, June 15, September 15, and December 15. This, in fact, is not true. The Internal Revenue Service (IRS) only requires that companies pay 22.5% of their annual income tax liability each quarter, with the final 10% due on March 15 of the year following the tax year.

Q. Does SWG take advantage of the IRS rule that allows it to pay 10% of its tax liability in the year following the tax year?

A. I am not aware of whether SWG takes advantage of the allowed lag. However, whether SWG avails itself of this opportunity or not is not germane to my recommendation. A company should practice prudent cash management policies and should only be reimbursed by ratepayers if the Company has efficiently managed its resources. Accordingly, as shown on Schedule MDC-3, page 3, I have recalculated SWG's income tax lag reflecting the 10% payment due in the following year. This adjustment increases the income lag from 37 days to 59.55 days.

Q. Please discuss your disagreement with the Company's calculation of Other O&M lag days.

A. The Company has computed lag days of 6.32 for its Other O&M expenses. This is an unusually short lag period for general O&M expenses, which typically are not due and payable except once a month.

Q. Did you examine the Company's calculation and determine why it generated such a short lag period for Other O&M expenses?

A. Yes. The Company's calculation is based on the monthly payment lags on individual vouchers that passed through its Accounts Payable account during the test year. Upon closer examination, it became apparent that the Company's calculations for the months of January, February, and April, had yielded substantial lead times for payments of expenses in those months. I then examined the vouchers that contributed to those expense leads and learned that although the Company had classified these vouchers as expenses, they were, in fact, prepayments.

Q. What is the difference between an expense and a prepayment?

A. An expense is an expenditure that provides a good or service that provides a benefit for a period of less than a year. Expenses are recorded on a company's income statement and become part of annual operating expenses. A prepayment is an expenditure that is made prior to the receipt of goods and services and provides a benefit for a period of one year or more. Prepayments are recorded on the balance sheet and amortized over the period in which they benefit.

Q. How did the Company's misclassification of these prepayments as expenses affect its calculation of cash working capital requirements?

A. This misclassification overstates the Company's cash working capital requirement by incorrectly attributing significant lead times for expenses that are, in fact, prepayments.

Q. What adjustment have you made?

A. I have removed the prepayments from the Other O&M lead/lag calculation and recomputed the lags days net of the prepayments. As shown on Schedule MDC-3, page 4, this increases the lag days for Other O&M from 6.32 days to 31.05 days. Next, as shown on Schedule MDC-3, page 5, I increased the Company's test year prepayment balance to include the prepayments that it had misclassified as expenses and then recalculated a 13-month average that included monthly amortization of the prepayment. This portion of the adjustment increased working capital by $625,957. Finally, I applied my recommended lag days to RUCO's recommended level of operating expense.

OPERATING INCOME

Operating Adjustment #8 - Compliance with Sarbanes Oxley Act

Q. What is the Sarbanes Oxley Act?

A. The Sarbanes Oxley Act (the Act) was enacted by Congress in 2000, largely in response to recent incidents that involved corporate fraudulent accounting practices. The Act, among other things, is intended to improve the accuracy and reliability of corporate disclosures made pursuant to securities laws. It imposes additional responsibilities and workload on both corporations and external auditors.

Q. Is the Company requesting any proforma adjustments related to the cost of complying with the Sarbanes Oxley Act?

A. Yes. The Company is requesting recovery of the estimated annual recurring cost of compliance with the Act, and for a deferral accounting order that would allow it to recover the initial one-time costs of Sarbanes Oxley compliance. SWG requests a three-year amortization of its estimated 2004 and 2005 one-time costs.

Q. Did you agree with the Company's estimates?

A. No. Pursuant to discovery, the Company provided documentation supporting the actual costs it had incurred in complying with the Act. Since the actual annual cost of compliance is now known and measurable, I have adjusted test year on-going O&M costs to reflect the actual cost of compliance to the Act. The initial one-time costs are also now known and I have adjusted amortization expense to reflect the actual initial one-time costs. This adjustment is shown on Schedule MDC-4, and increases test year expenses by $302,006 and decreases test year amortization expense by $12,932. I have also made an adjustment to remove the

Sarbane Oxley expenses that were recorded on the test year operating statement. Since the Company has requested deferral accounting and amortization for the test year recorded amounts, it is necessary to remove these amounts from the test year adjusted operating expense to avoid a double count. This portion of the adjustment decreases test year expenses by $61,990.

Operating Adjustment #11 - Leak Survey and Repair

Q. Please discuss the Company's proposed adjustment to test year leak survey and repair costs.

A. As discussed earlier in the rate base section of my testimony, Decision No. 58693 requires SWG to annually write off a percentage of its replacement costs for defective pipe. That decision also required the same annual percentage write off of the O&M cost of surveying and repairing leaks of the defective pipe. SWG is proposing the same modification to its required write offs of the O&M costs of defective pipe as it did the capital costs.

Q. Do you agree with the Company's proposal?

A. As discussed in Rate Base Adjustment #2, I believe on a going forward basis the Company-proposed 40 year life for purposes of writing off defective pipe is fair and reasonable and I have no objection to modifying the future write off schedule in the manner proposed by the Company.

Accordingly, no adjustment is proposed here for going forward leak survey and repair costs.

Operating Adjustment #12 -Transmission Integrity Management Program

Q. What is the Transmission Integrity Management Program?

A. The Transmission Integrity Management Program (TRIMP) is a program required under the Pipeline Safety Improvement Act of 2002 (the PSI Act). The PSI Act required the Office of Pipeline Safety and the Research and Special Programs Administration to promulgate regulations setting standards for transmission pipeline risk analysis and for the adoption and implementation of a pipeline integrity management program.

Q. Has SWG begun implementation of a TRIMP?

A. Yes. SWG began working on its baseline assessments for this program in 2004 and began repairs and replacements pursuant to this program in 2005. The Company is seeking a deferral accounting order for the estimated 2004 and 2005 initial costs of the TRIMP.

Q. What treatment is the Company requesting in the current case for TRIMP costs?

A. The Company is requesting that the estimated initial costs it will incur through the end of 2005 be deferred and amortized over three years. It is also requesting recovery of the annual on-going estimated cost of maintaining the TRIMP. The Company estimates the annual amortization of the 2004 and 2005 costs to be $1,183,333 and the on-going annual expense is estimated at $2,091,964.

Q. Do you agree with these estimates?

A. No. In RUCO data request 2-4 I asked the Company to provide all costs incurred to date for the TRIMP, to explain how it estimated the annual on-going costs of the TRIMP, and to update its on-going cost estimates, if applicable. In response, the Company provided the amounts it had actually deferred in 2004 and 2005, and provided the following information pursuant to its estimates of the on-going costs:

> The Company derived the estimates shown on Workpaper Schedule C-2 Adj., Sheets 1 of 3, based on information provided by the American Gas Association. The direct assessment costs were originally estimated to be $10,000 a mile. The Company has updated these estimates based on its experience to date.

Q. What adjustment are you proposing?

A. The costs the Company has actually experienced related to the TRIMP are significantly lower than those it estimated when putting the rate application together. Since the actual costs are now known and measurable, these amounts should be used for purposes of setting rates. On Schedule MDC-5, I have recalculated the revenue requirement associated with the TRIMP based on actual costs. In addition, I am recommending a seven-year amortization of the 2004 and 2005 costs, and believe it is more appropriate than the Company-proposed three-year amortization. The TRIMP program has a life cycle of ten years. My proposed seven-year amortization would spread the deferred costs over the remaining life cycle of the program. My adjustment for TRIMP reduces amortization expense by $1,044,968 and test year annual expenses by $1,488,287.

Operating Adjustment #17 - Amortization of Miscellaneous Intangible Plant

Q. Are you recommending an adjustment to the Company's proposed level of Amortization expense of its System Allocable Miscellaneous Intangible Plant?

A. Yes. As discussed in Rate Base Adjustment #4, the Company is requesting the removal of certain Miscellaneous Intangible Plant items because amortization of those plant items expired (i.e. was recovered) by December 31, 2004. The Company has also proposed an adjustment that would recognize new Intangible Plant items that were put in service by December 31, 2004. The Company's proposed adjustment utilized estimated in-service dates as well as estimated completed costs. The actual costs and in-service dates are now known, and accordingly I have adjusted these plant items to reflect actual costs and to remove one item that was not completed by December 31, 2004. This adjustment is shown on Schedule MDC-6 and decreases the amortization expense for Miscellaneous System Allocable Intangible Plant by $164,924.

Operating Adjustment #20 - Management Incentive Plan

Q. Are certain high-ranking employees of SWG awarded bonuses if the Company achieves specific performance objectives?

A. Yes. The Company has a bonus award system called the Management Incentive Plan (MIP). Eligibility for the MIP is limited to certain key management employees. No awards are payable under the MIP unless the Company's common stock dividend equals or exceeds the prior year's dividend and the Company's performance equals or exceeds a threshold percentage of specific performance targets.

Q. What are the performance targets?

A. The performance targets are return on equity, customers per employee, and customer satisfaction.

Q. Who benefits from the achievement of these performance targets?

A. Stockholders are the primary beneficiaries of the achievement of these performance targets. This is particularly true between rate cases.

Q. Please explain.

A. The achievement of the return on equity target clearly benefits stockholders. Any additional profits the Company is able to achieve between rate cases accrues solely to the Company's stockholders. Likewise, the achievement of the customer per employee target benefits stockholders. If the Company is successful in increasing its customer base without having to increase its number of employees, the additional profit will accrue to stockholders between rate cases. Accordingly, since stockholders stand to gain the most from achievement of the performance targets, stockholders should bear most of the cost of the MIP.

Q. Do employees who are eligible for the MIP awards also receive annual pay increases?

A. Yes. Awards made under the MIP are in addition to annual salary increases.

Q. Is the annual amount of the MIP a known and measurable expense?

A. No. Because the amount of the total MIP award is contingent on whether or not, and to the degree with, which the Company achieves its performance targets, the annual amount of the award is not known and measurable. For example, in 2002 the amount of the award was $2,813,935, in 2003 the amount was $3,619,075. Conceivably, if none of the performance targets are met the annual award could be zero. Thus, the amount awarded in the test year is not necessarily representative of the amount that will be incurred in subsequent years.

Q. Are you proposing an adjustment?

A. Yes. I recommend that the cost of the MIP be shared two-thirds by shareholders and one-third by ratepayers. Shareholders stand to enjoy the majority of the benefits realized through achievement of the MIP performance targets, particularly between rate cases. Amounts awarded under the MIP can be viewed as bonuses, since the selected individuals eligible for the award also receive wage and salary increases. Furthermore, the amount of the award is not known and measurable and conceivably could be as little as zero. Any amount collected in rates in excess of the amount actually awarded will provide the Company with additional profits not warranted under its authorized rate of return.

Q. Wasn't the MIP disallowed in a prior SWG rate case?

A. Yes. In Decision No. 57745, dated February 28, 1992, the Commission found that SWG's stockholders should bear the cost of the management bonuses. The decision allocated 100% of the cost of these bonuses to stockholders.

Q. Why then are you recommending a sharing of these costs between ratepayers and stockholders?

A. Since the issuance of Decision No. 57745, the Company has revised the criteria upon which the MIP bonuses are awarded. Previously the bonuses were based solely on the Company's achieved return on equity. As just discussed, the current MIP is based on return on equity, customers per employee ratios, and customer satisfaction. With the addition of the customer satisfaction criterion RUCO believes the bonus plan provides some benefit to customers, although the return on equity and customers per employee ratios continue to benefit primarily shareholders in the short run. Accordingly, I am recommending a sharing of the cost of the MIP.

Q. What adjustment have you made?

A. I have removed 67% of the test year cost of the MIP from test year expenses. This decreases expenses by $2,563,384.

DEMAND SIDE MANAGEMENT PROGRAMS

Q. Does SWG currently have any Demand Side Management Programs in place?

A. Yes. SWG currently has a Low Income Energy Conservation program and an Energy Advantage Pus program. Funding for these programs currently is $1,250,000, which is recovered through a $0.00486 surcharge per therm on residential customers.

Q. Is SWG proposing and changes to its DSM programs?

A. Yes. SWG is proposing to expand the scope of its current programs as well as establish some new programs. The Company's current DSM programs serve solely residential customers. The proposed DSM programs would also include programs for commercial and industrial customers. SWG proposes to increase its DSM funding to $4,385,000, and maintain the current surcharge recovery method. The surcharge would increase from the current $0.00486 per therm to $0.00724, however all customers would pay the surcharge, rather than solely residential customers which is the status quo.

Q. Does RUCO support expansion of SWG's DSM programs?

A. Yes. RUCO historically has advocated an aggressive approach to DSM. Well planned and funded DSM programs can go a long way to control load growth, forgo or at least forestall additional investment in capacity, as well as provide tools for customer bill management. DSM programs when properly designed and administered can be very cost effective. An aggressive DSM approach in a regulated monopoly model, as is the case here, can generate significant savings and benefits for ratepayers as well as stockholders.

Q. Does RUCO agree with the level of funding proposed by the Company?

A. Yes. The ratio between SWG's proposed DSM funding level and its test year revenues is nearly identical to the ratio that was approved for APS in its recent rate case. Further, the proposed increased funding level is material enough to allow a meaningful ramp up in the current level of DSM activity, and to broaden the reach of the programs to include commercial and industrial customers.

Q. Does RUCO agree with the DSM program design and approval process as proposed by the Company?

A. No. The Company has proposed a design and approval process that is the same as that utilized ten years ago. It merely provides that the funding level would be approved in this docket and then SWG would submit its proposed programs to ACC Staff for approval. Given the significant increase in funding that ratepayers will be required to pay for a more aggressive DSM approach, RUCO believes that the old procedures should be modified to insure that the DSM are dollars utilized in the most efficient and beneficial manner.

Q. How does RUCO propose that would be accomplished?

A. RUCO proposes a process similar to that which was adopted by the Commission in the recent APS rate case. The Commission in that case authorized a significant increase in DSM spending, as is requested here, and also saw fit to modify the design and approval process.

Q. Please outline RUCO's recommended process.

A. RUCO recommends the following design and approval process:

1) A collaborative DSM working group would be implemented and maintained to solicit and facilitate stakeholder input, advise SWG on program implementation, develop future DSM programs, and review DSM program performance. The DSM group would review draft DSM programs prior to submission to the Commission; however, SWG would retain responsibility for demonstrating to the Commission the appropriateness of its proposals. If SWG were to decide not to submit a DSM program, which was considered by the DSM group, any member of the group would be permitted to submit that proposal to the Commission. At minimum ACC Staff, RUCO, SWEEP, WRA, and any other party to this docket would be invited to participate in the DSM group.

2) The approval process would require that completed draft programs would be submitted Staff for review, and then docketed and submitted for Commission approval.

Q. What is SWG's position regarding net revenue that potentially could be lost as a result of an aggressive DSM approach?

A. The Company indicates that its proposed CMT mechanism would allow it to recover any net revenues lost as a result of the more aggressive DSM approach.

Q. Leaving aside RUCO's position as a whole on SWG's proposed CMT mechanism, do you believe that it is appropriate to embed in today's rates a recovery mechanism for potential future changes in consumption levels resulting from DSM programs?

A. No. Such a notion violates myriad ratemaking principles including the matching, and known and measurable principles, as well as the undesirability of piecemeal ratemaking concept. Such a mechanism would single out one element of ratemaking formula for adjustment and ignore changes in other ratemaking factors such as growth, increases or decreases in expenses, investment, and capital costs. Mismatches would result, potentially creating biased and unfair rates. Changes in consumption levels that result from DSM measures should be examined only in the context of a rate case where all other elements of the ratemaking formula can also be examined.

Q. Please summarize RUCO DSM position.

A. RUCO recommends the following:

1) Approval of the increased level of DSM funding in the amount of $4,385,00, as proposed by SWG;

2) Expansion of the current scope of the DSM programs to also include commercial and industrial customers;

3) Retention of the current surcharge recovery method modified to include commercial and industrial customers;

4) Creation of a DSM collaborative group;

5) A requirement that proposed DSM programs must be submitted and receive Commission approval prior to implementation; and

6) A requirement that potential changes in revenue levels as a result DSM efforts will be examined in SWG's next rate case and addressed in that context.

RATE DESIGN

Conservation Margin Tracker

Q. What is the Conservation Margin Tracker?

A. The Conservation Margin Tracker (CMT) is a mechanism proposed in the instant case by SWG which according to their witness would "decouple Southwest's recovery of residential authorized non-gas revenue (margin) per customer from the level of sales."

Q. What does that mean?

A. Effectively, the proposed CMT would operate as a take or pay charge. The mechanism would measure each residential customer's month-to-month consumption against the average level of residential monthly consumption embedded in the rates (average residential margin per customer) ultimately authorized in this docket. To the extent that a customer used less than the average residential margin per customer it would be billed for that shortfall. Likewise, if more than the average were used, the customer would not be billed for the margin used above average. The Company claims this mechanism is necessary to compensate for the revenue that will be lost as a result of their DSM efforts.

Q. Please discuss RUCO's view of the proposed CMT.

A. RUCO does not support the proposed mechanism, and believes it will result in biased rates. First, the mechanism would require customers to pay for a predetermined level gas service regardless of whether that level was actually used. Second, the mechanism as proposed is restricted to residential customers despite the fact that commercial and industrial customers are also targeted under SWG's proposed DSM programs. Lastly, despite the Company's argument that the mechanism is necessary because its costs are primarily fixed in nature so that decreases in consumption do not result in decreases in cost to serve, that argument does not warrant implementation of a mechanism that would have customers pay for therms they did not consume. In fact, a mechanism that sent such a price signal would be counterproductive, especially when coupled with increased DSM conservation efforts.

Q. Has SWG proposed this type of rate adjustor mechanism in any other of its rate jurisdictions?

A. Yes. SWG proposed this type of mechanism in its recent Nevada rate case. In that proceeding the Company called the mechanism the "Margin Per Customer Balancing Provision (MCB)", however, substantively it functioned in the same manner as the CMT proposed in this docket.

Q. How did the Nevada Commission rule regarding this issue?

A. The Commission denied the mechanism, stating:

> There can be no question that establishing the MCB as proposed by Southwest would be a significant change from current practices. Before a significant change is authorized, the Commission must be able to arrive at the conclusion that the proposed change is the right thing to do to address the perceived problem. The Commission cannot conclude that the evidence is compelling to establish the MCB, especially prior to using other more recognized alternatives. Consequently, the Commission is not prepared to amend Southwest's billing practice in such a drastic manner at this time. [Order of the Public Utilities Commission of Nevada in Docket No. 04-0311, Pg. 76, Southwest Gas Corporation]

Q. Do you agree with the opinions express by the Nevada Commission regarding the proposed mechanism?

A. The Nevada Commission appears to have reached some of the same conclusions as RUCO. An automatic adjustor mechanism that would bill customers for therms it did not use not only is inherently unfair, but also is conceptually unacceptable. It certainly is an extreme and unprecedented resolution to a routine rate design issue.

Q. What is the routine rate issue that needs to be resolved in this proceeding?

A. The issue is simply how should the revenue requirement established in this case be allocated among the various rate schedules, and allocated between the commodity rates and the monthly service charge. The solution to this issue should balance the following three goals:

1) Result in a fair and reasonable rates for each rate schedule;
2) Encourage energy efficient usage;
3) Give the Company a fair opportunity to realize its authorized rate of return.

RUCO believes its proposed rate design will achieve these somewhat conflicting goals without resorting to extreme measures such as the proposed CMT. Accordingly, RUCO recommends that the proposed CMT be denied and in its stead that RUCO's recommended rate design be adopted in resolution of the above-identified ratemaking goals.

Rate Structure

Q. Please discuss the salient features of your proposed rate design.

A. RUCO is proposing four fundamental changes in SWG's current rate design, which are as follows:

1) Shift a portion of the revenue requirement that is currently recovered from the commodity rates to the fixed monthly charge;

2) Flatten the current declining tier commodity rate structure to one uniform commodity rate for all usage;

3) Add a new residential rate schedule for multi-family housing; and

4) Eliminate the summer and winter rate structure differential.

Q. Please describe your first fundamental change to SWG's existing rate structure.

A. I have reallocated some of the revenue that the Company currently recovers from its commodity charges to the monthly service charge.

Q. Please explain how this reallocation was accomplished.

A. Utilizing SWG's test year revenue under the current rate structure, I calculated the percentage of total revenue that is recovered from residential and commercial customers, respectively. Current residential rates generate 67.16% of the total revenue requirement and commercial rates generate 32.84%. My recommended rate design holds this percentage constant. As a result, my recommended rate design does not shift revenue from one class to another. Next, I calculated the percentage of residential revenue at current rates that is recovered through the monthly service charge and the percentage of commercial revenue that is recovered through the monthly service charge. These percentages were 37.42% for the residential class and 24.65% for the commercial class. I then increased the percentages that will be recovered from the monthly service charge for the residential class and for the commercial class. My recommended rate structure will generate 41.16% of the residential revenue from the monthly service charge and 32.05% of the commercial revenue from the monthly service charge. This also had the effect of decreasing the amount of revenue to be recovered through the commodity charges.

Q. Why are you recommending a shift in revenue recovery from the commodity rate to the fixed monthly charge?

A. As discussed earlier, RUCO opposes SWG's proposed CMT mechanism. However, this is not to say that many of the issues and concerns the Company cites for wanting a CMT do not have some validity. These concerns include the continued decline in average customer consumption, the relative proportion between the Company fixed and variable costs to its existing fixed and variable rates, and the resultant strain that puts on the Company's opportunity to recover its authorized rate of return.

RUCO's recommended incremental shift in revenue recovery from variable rates (commodity) to fixed rates (monthly service charge) is designed to move the current rate structure to more accurately mirror the fixed vs. variable nature of the Company's cost of service. This shift will afford the Company a better opportunity to recover its costs, even if average customer consumption declines. My recommended rate structure also more fairly addresses the Company's fixed vs. variable rate concerns because it applies the remedy to both residential and commercial customers, whereas SWG's proposed CMT would hold residential customers responsible for the entire remedy.

Q. Please describe RUCO's second fundamental recommended change in the Company's rate structure.

A. I have eliminated SWG's two tiered declining rate structure for residential customers and replaced it with a single commodity rate for each rate schedule. This was not necessary for the commercial rate schedules because the existing rate structure is flat. Thus, under my recommended rate structure each customer within each rate schedule will pay the same amount per therm regardless of the volume consumed.

Q. Why are you recommending a flat or one-tiered rate structure?

A. SWG's current two-tiered declining rate structure is counterintuitive to energy efficient consumption. Under current rates the more therms a customer consumes over a certain threshold the less he/she will pay per therm. As discussed earlier, RUCO supports SWG's proposed expanded DSM efforts. It would be counterproductive on the one hand to support increased spending to promote energy efficient usage and at the same time recommend a rate structure that provides a discounted commodity rate to large users.

Q. Why then aren't you recommending an inclining two-tiered rate structure?

A. While an inclining two-tiered rate structure would send an even stronger energy efficiency price signal than a flat rate structure, the sole objective of an effective and fair rate design is not merely the promotion of energy efficiency. A rate structure that is based on the cost to serve the various rate classes is the cornerstone of a fair and effective rate design. While cost of service is the starting point of a good rate design, it is sometimes warranted and even desirable to make small departures from pure cost of service rate structures in an effort to send price signals designed to elicit certain behaviors. A total departure from cost of service, however, is contrary to fundamental fairness and accepted rate design principles. As a gas distribution company, SWG's cost of service declines as usage increases. Thus, a recommendation to use an inclining tier rate structure in a declining commodity cost business would depart too far from cost of service. At the same time, however, the current declining commodity rate structure is counterproductive to the energy efficiency goal of the proposed DSM programs. My recommended flat rate structure adheres more closely to cost of service and at the same time does not send a price signal that discourages energy efficiency, as would continuation of the declining rate structure.

Q. Please discuss your third change to the existing SWG rate structure.

A. My recommended rate design includes a new rate schedule (Rate Schedule G-6) within the residential class for residential multi-family homes. SWG's cost of service study reflects differences in the cost to serve multi-family residences vs. single-family residences. The new rate schedule G-6 reflects the lower cost of serving these customers. SWG's proposed rate design also includes the new rate schedule G-6, thus, in this respect RUCO's recommendation is the same as the Company's.

Q. Please discuss your fourth fundamental recommended change in the Company's rate structure.

A. My recommended rate structure eliminates the existing distinction in residential rates between summer and winter.

Q. What distinction do SWG's existing residential rates make for the summer and winter seasons?

A. SWG's existing residential monthly service charges and commodity rates are the same for summer and winter. The only distinction that the rates make between the two seasons is the break-over point between the first tier commodity rate and the second tier. The existing residential summer rates break-over point is 20 therms and the existing winter break-over point is 40 therms. Since my recommended rate design includes a flat residential commodity rate across all therm usage the distinction between summer and winter rates is no longer applicable.

Q. Why should your recommended rate structure be approved?

A. My recommended rate structure was designed specifically to address some of Company's cost recovery problems, to send a price signal that will not discourage energy efficient gas usage, while at the same time protect ratepayers from extreme and abrupt changes in their monthly bill. I believe my recommended rate design addresses those objectives through adherence to basic rate design principles of cost of service, gradualism, and the appropriate price signals.

Q. Will your recommended rate design accomplish the three goals you identified earlier?

A. Yes, I believe it will. RUCO's recommended rates are fair and reasonable, are designed to encourage energy efficient usage, and afford the Company an opportunity to recover its authorized rate of return.

Q. Does that conclude your direct testimony?

A. Yes.

APPENDIX I

Qualifications of Marylee Diaz Cortez

EDUCATION: University of Michigan, Dearborn
B.S.A., Accounting 1989

CERTIFICATION: Certified Public Accountant - Michigan
Certified Public Accountant - Arizona

EXPERIENCE: Audit Manager
Residential Utility Consumer Office
Phoenix, Arizona 85007
July 1994 - Present

Responsibilities include the audit, review and analysis of public utility companies. Prepare written testimony, schedules, financial statements and spreadsheet models and analyses. Testify and stand cross-examination before Arizona Corporation Commission. Advise and work with outside consultants. Work with attorneys to achieve a coordination between technical issues and policy and legal concerns. Supervise, teach, provide guidance and review the work of subordinate accounting staff.

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona 85004
October 1992 - June 1994

Responsibilities included the audit, review and analysis of public utility companies. Prepare written testimony and exhibits. Testify and stand cross-examination before Arizona Corporation Commission. Extensive use of Lotus 123, spreadsheet modeling and financial statement analysis.

Auditor/Regulatory Analyst
Larkin & Associates - Certified Public Accountants
Livonia, Michigan
August 1989 - October 1992

Performed on-site audits and regulatory reviews of public utility companies including gas, electric, telephone, water and sewer throughout the continental United States. Prepared integrated proforma financial statements and rate models for some of the largest public utilities in the United States. Rate models consisted of anywhere from twenty to one hundred fully integrated schedules. Analyzed financial statements, accounting detail, and identified and developed rate case issues based on this analysis. Prepared written testimony, reports, and briefs. Worked closely with outside legal counsel to achieve coordination of technical accounting issues with policy, procedural and legal concerns. Provided technical assistance to legal counsel at hearings and depositions. Served in a teaching and supervisory capacity to junior members of the firm.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Client
Potomac Electric Power Co.	Formal Case No. 889	Peoples Counsel of District of Columbia
Puget Sound Power & Light Co.	Cause No. U-89-2688-T	U.S. Department of Defense - Navy
Northwestern Bell-Minnesota	P-421/EI-89-860	Minnesota Department of Public Service
Florida Power & Light Co.	890319-EI	Florida Office of Public Counsel
Gulf Power Company	890324-EI	Florida Office of Public Counsel
Consumers Power Company	Case No. U-9372	Michigan Coalition Against Unfair Utility Practices
Equitable Gas Company	R-911966	Pennsylvania Public Utilities Commission
Gulf Power Company	891345-EI	Florida Office of Public Counsel

Jersey Central Power & Light	ER881109RJ	New Jersey Department of Public Advocate Division of Rate Counsel
Green Mountain Power Corp.	5428	Vermont Department of Public Service
Systems Energy Resources	ER89-678-000 & EL90-16-000	Mississippi Public Service Commission
El Paso Electric Company	9165	City of El Paso
Long Island Lighting Co.	90-E-1185	New York Consumer Protection Board
Pennsylvania Gas & Water Co.	R-911966	Pennsylvania Office of Consumer Advocate
Southern States Utilities	900329-WS	Florida Office of Public Counsel
Central Vermont Public Service Co.	5491	Vermont Department of Public Service
Detroit Edison Company	Case No. U-9499	City of Novi
Systems Energy Resources	FA-89-28-000	Mississippi Public Service Commission
Green Mountain Power Corp.	5532	Vermont Department of Public Service
United Cities Gas Company	176-717-U	Kansas Corporation Commission

General Development Utilities	911030-WS & 911067-WS	Florida Office of Public Counsel
Hawaiian Electric Company	6998	U.S. Department of Defense - Navy
Indiana Gas Company	Cause No. 39353	Indiana Office of Consumer Counselor
Pennsylvania American Water Co.	R-00922428	Pennsylvania Office of Consumer Advocate
Wheeling Power Co.	Case No. 90-243-E-42T	West Virginia Public Service Commission Consumer Advocate Division
Jersey Central Power & Light Co.	EM89110888	New Jersey Department of Public Advocate Division of Rate Counsel
Golden Shores Water Co.	U-1815-92-200	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-92-135	Residential Utility Consumer Office
Sulphur Springs Valley Electric Cooperative	U-1575-92-220	Residential Utility Consumer Office
North Mohave Valley Corporation	U-2259-92-318	Residential Utility Consumer Office
Graham County Electric Cooperative	U-1749-92-298	Residential Utility Consumer Office

Graham County Utilities	U-2527-92-303	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-93-110	Residential Utility Consumer Office
Litchfield Park Service Co.	U-1427-93-156 & U-1428-93-156	Residential Utility Consumer Office
Pima Utility Company	U-2199-93-221 & U-2199-93-222	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-94-306	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-182	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-310 & U-1303-94-401	Residential Utility Consumer Office
Pima Utility Company	U-2199-94-439	Residential Utility Consumer Office
SaddleBrooke Development Co.	U-2492-94-448	Residential Utility Consumer Office
Boulders Carefree Sewer Corp.	U-2361-95-007	Residential Utility Consumer Office
Rio Rico Utilities	U-2676-95-262	Residential Utility Consumer Office
Rancho Vistoso Water	U-2342-95-334	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-95-491	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-473	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-417 et al.	Residential Utility Consumer Office

Paradise Valley Water	U-1303-96-283 & U-1303-95-493	Residential Utility Consumer Office
Far West Water	U-2073-96-531	Residential Utility Consumer Office
Southwest Gas Corporation	U-1551-96-596	Residential Utility Consumer Office
Arizona Telephone Company	T-2063A-97-329	Residential Utility Consumer Office
Far West Water Rehearing	W-0273A-96-0531	Residential Utility Consumer Office
SaddleBrooke Utility Company	W-02849A-97-0383	Residential Utility Consumer Office
Vail Water Company	W-01651A-97-0539 & W-01651B-97-0676	Residential Utility Consumer Office
Black Mountain Gas Company Northern States Power Company	G-01970A-98-0017 G-03493A-98-0017	Residential Utility Consumer Office
Paradise Valley Water Company Mummy Mountain Water Company	W-01303A-98-0678 W-01342A-98-0678	Residential Utility Consumer Office
Bermuda Water Company	W-01812A-98-0390	Residential Utility Consumer Office
Bella Vista Water Company Nicksville Water Company	W-02465A-98-0458 W-01602A-98-0458	Residential Utility Consumer Office
Paradise Valley Water Company	W-01303A-98-0507	Residential Utility Consumer Office
Pima Utility Company	SW-02199A-98-0578	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144 Interim Rates	Residential Utility Consumer Office
Vail Water Company	W-01651B-99-0355 Interim Rates	Residential Utility Consumer Office

Far West Water & Sewer Company	WS-03478A-99-0144	Residential Utility Consumer Office
Sun City Water and Sun City West	W-01656A-98-0577 & SW-02334A-98-0577	Residential Utility Consumer Office
Southwest Gas Corporation ONEOK, Inc.	G-01551A-99-0112 G-03713A-99-0112	Residential Utility Consumer Office
Table Top Telephone	T-02724A-99-0595	Residential Utility Consumer Office
U S West Communications Citizens Utilities Company	T-01051B-99-0737 T-01954B-99-0737	Residential Utility Consumer Office
Citizens Utilities Company	E-01032C-98-0474	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-00-0309 & G-01551A-00-0127	Residential Utility Consumer Office
Southwestern Telephone Company	T-01072B-00-0379	Residential Utility Consumer Office
Arizona Water Company	W-01445A-00-0962	Residential Utility Consumer Office
Litchfield Park Service Company	W-01427A-01-0487 & SW-01428A-01-0487	Residential Utility Consumer Office
Bella Vista Water Co., Inc.	W-02465A-01-0776	Residential Utility Consumer Office
Generic Proceedings Concerning Electric Restructuring Issues	E-00000A-02-0051	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-02-0707	Residential Utility Consumer Office
Qwest Corporation	RT-00000F-02-0271	Residential Utility Consumer Office

Arizona Public Service Company	E-01345A-02-0403	Residential Utility Consumer Office
Citizens/UniSource	G-01032A-02-0598 E-01032C-00-0751 E-01933A-02-0914 E-01302C-02-0914 G-01302C-02-0914	Residential Utility Consumer Office
Arizona-American Water Company	WS-01303A-02-0867	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-03-0437	Residential Utility Consumer Office
UniSource	E-04230A-03-0933	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-04-0407	Residential Utility Consumer Office
Qwest Communications, Inc.	T-01051B-03-0454 et al.	Residential Utility Consumer Office

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJ #2 - PIPE REPLACEMENT

DOCKET NO. G-0155A-04-0876
SCHEDULE MDC-1

LINE NO.	DESCRIPTION	2000	2001	2002	2003	2004	PLANT ADJUSTMENT	ACCUMULATED DEPRECIATION	DEFERRED TAXES
	ALDYL HD MAINS								
1	REPLACEMENT COST	$15,796	150,399	91,463	82,185	39,107			
2	DISALLOWANCE %	69%	68%	67%	66%	65%			
3	DISALLOWANCE	10,899	102,271	61,280	54,242	25,420	254,112	(32,436)	(18,044)
	ALDYL HD SERVICES								
4	REPLACEMENT COST	203,854	564,117	580,723	728,319	650,523			
5	DISALLOWANCE %	69%	68%	67%	66%	65%			
6	DISALLOWANCE	140,659	383,600	389,084	480,691	422,840	1,816,874	(262,907)	(147,597)
	ALDYL A MAINS								
7	REPLACEMENT COST	149,649	353,479	221,454	938,175	505,054		(133,150)	(312,132)
8	DISALLOWANCE %	29.5%	28.5%	27.5%	26.5%	25.5%		27.5%	27.5%
9	DISALLOWANCE	44,146	100,742	60,900	248,616	128,789	583,193	(36,616)	(85,836)
	ALDYL A SERVICES								
10	REPLACEMENT COST	281,898	188,129	462,608	239,342	138,873		(164,202)	(131,110)
11	DISALLOWANCE %	29.5%	28.5%	27.5%	26.5%	25.5%		27.5%	27.5%
12	DISALLOWANCE	83,160	53,617	127,217	63,426	35,413	362,832	(45,156)	(36,055)
	1960s STEEL MAINS								
13	REPLACEMENT COST	502,862	412,904	1,030,498	1,982,344	1,122,435		(317,916)	(733,426)
14	DISALLOWANCE %	12.5%	11.5%	10.5%	9.5%	8.5%		10.5%	10.5%
15	DISALLOWANCE	62,858	47,484	108,202	188,323	95,407	502,274	(33,381)	(77,010)
	1960s STEEL SERVICES								
16	REPLACEMENT COST	213,653	289,859	360,912	222,417	206,039		(154,667)	(129,542)
17	DISALLOWANCE %	12.5%	11.5%	10.5%	9.5%	8.5%		10.5%	10.5%
18	DISALLOWANCE	26,707	33,334	37,896	21,130	17,513	136,579	(16,240)	(13,602)
	ALDYL ABS MAINS								
19	REPLACEMENT COST	459	4,643	0	301,527	67,905		(14,937)	(67,084)
20	DISALLOWANCE %	18.0%	17.0%	16.0%	15.0%	14.0%		16%	16%
21	DISALLOWANCE	83	789	0	45,229	9,507	55,608	(2,390)	(10,733)
	ALDYL ABS SERVICES								
22	REPLACEMENT COST	1,572	0	0	297	0		(366)	(98)
23	DISALLOWANCE %	18.0%	17.0%	16.0%	15.0%	14.0%		0	0
24	DISALLOWANCE	283	0	0	45	0	328	(59)	(16)
25	TOTAL	368,795	721,836	784,580	1,101,701	734,888	3,711,799	(429,184)	(388,893)
26	TOTAL PER COMPANY						1,372,020	(295,343)	(165,641)
27	ADJUSTMENT						($2,339,779)	$133,841	$223,252

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJ #4 - MISC INTANGIBLE PLANT
SYSTEM ALLOCABLE

DOCKET NO. G-01551A-04-0876
SCHEDULE MDC-2

LINE NO.	DESCRIPTION	(A) COMPANY REQUESTED	(B) RUCO RECOMMENDED	(C) ADJUSTMENT
	ACCT 303 PLANT			
1	EMRS SOFTWARE	$212,459	212,459	0
2	RISER VERIFICATION	500,000	0	(500,000)
3	DB MICROWAVE SOFTWARE	277,000	267,153	(9,847)
4	SOFTWARE LICENSES - MOBILE	434,000	454,500	20,500
5	MICROFICHE SOFTWARE	50,000	44,579	(5,421)
6	165 PERPETUAL PGP	44,418	0	(44,418)
7	UTILITY PARTNERS	820,000	0	(820,000)
8	TELLER TERMINAL	405,000	0	(405,000)
9	MICROSOFT SOFTWARE	618,633	0	(618,633)
10	PLANT TOTAL	3,361,510	978,691	($2,382,819)
	ACCUM. DEPRECIATION			
11	EMRS SOFTWARE	0	0	0
12	RISER VERIFICATION	0	0	0
13	DB MICROWAVE SOFTWARE	0	0	0
14	SOFTWARE LICENSES - MOBILE	0	0	0
15	MICROFICHE SOFTWARE	0	0	0
16	165 PERPETUAL PGP	(44,418)	0	44,418
17	UTILITY PARTNERS	(797,236)	0	797,236
18	TELLER TERMINAL	(393,750)	0	393,750
19	MICROSOFT SOFTWARE	(301,440)	0	301,440
20	ACCUM. DEPRECIATION TOTAL	(1,536,844)	0	$1,536,844

REFERENCES
COLUMN (A): SCH. C-2 W/P, ADJ 17, SHEET 8 & 9
COLUMN (B): TESTIMONY MDC, RUCO DR# 2-16
COLUMN (C): COLUMN (B) - COLUMN (A)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL

DOCKET NO. G-0155A-04-0876
SCHEDULE MDC-3

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	MATERIALS & SUPPLIES PER SWG	$9,222,489	SCH. B-5, PG. 3
2	MATERIALS & SUPPLIES PER RUCO	9,222,489	SCH. B-5, PG. 3
3	ADJUSTMENT	0	LINE 2 - LINE 1
4	PREPAYMENTS PER SWG	2,740,815	SCH. B-5, PG. 4
5	PREPAYMENTS PER RUCO	3,366,772	SCH. MDC-3, Pg 5
6	ADJUSTMENT	625,957	LINE 5 - LINE 4
7	CASH WORKING CAPITAL PER SWG	(11,082,156)	SCH. B-5, PG. 2
8	CASH WORKING CAPITAL PER RUCO	(15,357,713)	SCHEDULE MDC-3, Pg 2
9	ADJUSTMENT	(4,275,557)	LINE 8 - LINE 7
10	TOTAL ADJUSTMENT	($3,649,600)	SUM OF LINES 3, 6 & 9

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) EXPENSE PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
1	COST OF GAS	$298,559,015		298,559,015	43.78	13,070,913,677
2	LABOR COST	107,117,974	(4,235,547)	102,882,427	14.01	1,441,382,804
3	UNCOLLECTIBLE	1,498,151		1,498,151	120.00	179,778,120
4	OTHER O&M	45,068,143	(7,203,716)	37,864,427	31.05	1,175,546,908
5	INTEREST	40,521,530	(4,061,931)	36,459,599	87.34	3,184,381,359
6	TAXES OTHER THAN INCOME	33,455,124	(1,267,863)	32,187,261	206.50	6,646,669,500
7	INCOME TAXES	18,192,843	9,698,766	27,891,609	59.55	1,660,945,319
8	TOTAL OPERATING EXPENSES	544,412,780		537,342,489		27,359,617,686
9	EXPENSE LAG				50.92	
10	REVENUE LAG				40.62	
11	NET LAG				(10.30)	
12	CASH WORKING CAPITAL	($15,357,713)				

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL
CALCULATION OF INCOME TAX LAG

DOCKET NO. G-0155A-04-0876
SCHEDULE MDC-3

LINE NO.	MID-POINT OF SERVICE PERIOD	PAYMENT DATE	PERCENT PAYMENT	(LEAD)/LAG DAYS	DOLLAR DAYS
1	7/1/2003	4/15/2003	22.50%	(77)	(17.33)
2	7/1/2003	6/15/2003	22.50%	(16)	(3.60)
3	7/1/2003	9/15/2003	22.50%	76	17.10
4	7/1/2003	12/15/2003	22.50%	167	37.58
5	7/1/2003	3/15/2004	10.00%	258	25.80
6	TOTALS		100.00%		59.55
7	INCOME TAX LAG			59.55	

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL
CALCULATION OF OTHER O&M LAG

DOCKET NO. G-0155A-04-0876
SCHEDULE MDC-3
PAGE 4 OF 5.

Line No.	Month	Cost	Lag Days	Dollar Days
	(a)	(b)	(c)	(d)
1	September 2003	$2,065,502	27.14	56,065,384
2	October 2003	2,281,209	24.19	55,183,873
3	November 2003	2,122,438	14.51	30,806,560
4	December 2003	2,799,950	19.45	54,459,832
5	January 2004	1,619,271	76.74	124,263,026
6	February 2004	1,310,710	46.31	60,700,671
7	March 2004	2,873,308	32.15	92,368,700
8	April 2004	1,937,390	17.71	34,308,766
9	May 2004	1,865,981	24.72	46,127,781
10	June 2004	2,515,719	48.84	122,871,846
11	July 2004	3,728,708	22.06	82,248,601
12	August 2004	2,172,721	40.47	87,936,239
13	Total	$27,292,907	31.05	847,341,280

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL
CALCULATION OF ADJUSTED PREPAYMENTS

LINE NO.	MONTH	(A) BALANCE	(B) DEBITS	(C) CREDITS	(D) ADJUSTED BALANCE
1	AUGUST	$5,130,082			5,130,082
2	SEPTEMBER	4,798,680			4,798,680
3	OCTOBER	3,784,576	66,608	0	3,851,184
4	NOVEMBER	3,956,561	12,000	5,551	4,029,618
5	DECEMBER	5,938,689	119,223	6,551	6,124,419
6	JANUARY	5,258,062	697,011	16,486	6,124,317
7	FEBRUARY	4,984,761	958,218	74,570	6,734,664
8	MARCH	4,810,591	295,000	154,422	6,701,072
9	APRIL	4,204,986	408,228	179,005	6,324,690
10	MAY	4,296,987	153,500	213,024	6,357,167
11	JUNE	3,639,813	27,754	225,816	5,501,931
12	JULY	3,377,801	105,000	228,129	5,116,791
13	AUGUST	7,698,845	17,007	236,879	9,217,963
14	TOTAL	61,880,434			76,012,577
15	13 MONTH AVERAGE	$4,760,033		57.58%	$3,366,772

REFERENCES
COLUMN (A): SCH. B-5, PG. 4
COLUMN (B): SCH. B-5 W/P SHEET 30-59
COLUMN (C): COLUMN (B) PRIOR MOS. ACCRUALS / 12 MONTHS
COLUMN (D): PRIOR MONTH COLUMN (D) + CURRENT MONTH COLUMN (B) - CURRENT MONTH COLUMN (C) + CURRENT MONTH COLUMN (A) - PRIOR MONTH COLUMN (A)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
OPERATING ADJ # 8 - SARBANES OXLEY

DOCKET NO. G-01551A-04-0876
SCHEDULE MDC-4

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
	ANNUAL EXPENSE		
1	ANNUAL SOX AUDIT FEES	$915,000	STAFF DR JJD 8-2
2	PAIUTE & SGTC ALLOCATION	(39,229)	STAFF DR JJD 8-2
3	SUBTOTAL	875,771	LINE 1 + LINE 2
4	ARIZONA 4-FACTOR	57.58%	SCH. C-2, ADJ. 8
5	AMT ALLOCATED TO ARIZONA	504,269	LINE 3 x LINE 4
6	AMT. AS FILED	202,263	SCH. C-2, ADJ. 8
7	ADJUSTMENT	$302,006	LINE 5 - LINE 6
	AMORT. OF DEFERRALS		
8	AMORT. OF DEFERRED SABANNES OXLEY	$14,414	STAFF JJD 8-2
9	AMOUNT PER COMPANY	27,346	SCH. C-2, ADJ. 8
10	ADJUSTMENT	($12,932)	LINE 1- LINE 2
	REMOVE DOUBLE COUNT OF T/Y SOX COSTS		
11	SOX T/Y EXPENSES - ACCTS. 921 & 923	($61,990)	STAFF DR JJD 8-2

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
OPERATING ADJ #12 - TRIMP COSTS

DOCKET NO. G-01551A-04-0876
SCHEDULE MDC-5

LINE NO.	DESCRIPTION	(A) 2004	(B) 2005	(C) TOTAL	(D) AS FILED		(E) ADJUSTMENT
	DEFERRED COSTS						
1	DIRECT ASSESSMENT	414,227	254,405	668,632	887,500		
2	DIRECT EXAMINATION	0	299,925	299,925	2,662,500		
3	TOTAL DEFERRED	414,227	554,330	968,557	3,550,000		
4	7 YEAR AMORTIZATION			138,365	1,183,333	(A)	$\boxed{(1,044,968)}$
	ANNUAL EXPENSES						
5	DIRECT ASSESSMENT			218,060	380,357		(162,297)
6	DIRECT EXAMINATION			257,078	1,141,071		(883,993)
7	REPAIR AND MAINTENANCE			128,539	570,536		(441,997)
8	TOTAL O&M			603,677	2,091,964		$\boxed{(1,488,287)}$

REFERENCES
ALL REVISED ESTIMATES IN COLUMNS (A) AND (B) ARE PER RUCO DR #2-04

(A) AS FILED REFLECTS A 3 YEAR AMORTIZATION

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
OPERATING ADJ #17 - AMORTIZATION OF
SYSTEM ALLOCABLE INTANGIBLE PLANT

DOCKET NO. G-01551A-04-0876
SCHEDULE MDC-6

LINE NO.	DESCRIPTION	(A) COMPANY REQUESTED AMORT.	(B) RUCO ADJUSTED	(C) ADJUSTMENT
1	EMRS SOFTWARE	$70,820	70,820	(0)
2	RISER VERIFICATION	166,667	0	(166,667)
3	DB MICROWAVE SOFTWARE	92,333	89,051	(3,282)
4	SOFTWARE LICENSES - MOBILE	144,667	151,500	6,833
5	MICROFICHE SOFTWARE	16,667	14,860	(1,807)
6	TOTALS	$491,154	$326,230	($164,924)

REFERENCES
COLUMN (A): W/P SCH. C-2, ADJ. 17, SHEET 9
COLUMN (B): SCH. MDC- , LINES 1 THROUGH 5/3 YEARS
COLUMN (C): COLUMN B) - COLUMN (A)

EXHIBIT
tabbies
RUCO-4
Admitted

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-04-0876

SURREBUTTAL TESTIMONY

OF

MARYLEE DIAZ CORTEZ

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

SEPTEMBER 13, 2005

INTRODUCTION

Q. Please state your name for the record.

A. My name is Marylee Diaz Cortez.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony in this docket on November 18, 2004.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to various arguments and opinions SWG witnesses have set forth in their rebuttal testimony, as well as identify certain revisions RUCO has made to its direct filing.

Q. Please summarize the issues you will address in your surrebuttal testimony.

A. My surrebuttal testimony will address the following:

* Revisions to RUCO direct filing
* Conservation Margin Tracker
* Rate Design
* Demand Side Management
* Pipe Replacement
* Compliance with Sarbanes Oxley Act

* Transmission Integrity Management Plan
* Management Incentive Plan

RUCO REVISIONS

Q. Have you made any revisions to your recommended adjustments as filed in your direct testimony?

A. Yes. I have revised two of my recommended adjustments. These revisions pertain to my Rate Base Adjustment # 4 - Miscellaneous Intangible Plant and Rate Base Adjustment #6 - Working Capital.

Q. Please discuss your revisions to Rate Base Adjustment #4.

A. I have corrected a typographical error on Schedule MDC-2, line 19, column (c). This correction has the effect of increasing the accumulated depreciation portion of the adjustment by $300,000. I have also made a correction to Schedule RLM-2, page 2, column (J). RUCO's direct filing reflected the adjustment in column (J) net of accumulated depreciation, when in fact the adjustment should have been reflected at its gross value since the accumulated depreciation portion of Rate Base Adjustment #4 is already reflected in column (L).

Q. Please discuss your revisions to Rate Base Adjustment #6 - Working Capital.

A. I have revised my calculation of SWG's income tax lag on Schedule MDC-3, page 3 to reflect the recent change in the IRS requirements for estimated tax payments.

Q. What effect do these revisions have on RUCO's recommended revenue requirement?

A. RUCO's other revenue requirements witness Rodney Moore has also made certain revisions to some of his adjustments. These revisions are discussed in his surrebuttal testimony, as well as the overall cumulative effect that RUCO's revisions have on revenue requirements.

CONSERVATION MARGIN TRACKER

Q. Have you reviewed the Company's rebuttal testimony regarding the CMT?

A. Yes. The Company continues to maintain that its proposed CMT is a vital piece of its overall rate request, and rebuts the Staff and RUCO recommendation to deny the CMT.

Q. What specific RUCO arguments does the Company rebut?

A. The Company provides rebuttal comments to the following RUCO arguments:

1) The proposed CMT is biased since it would only be applicable to residential ratepayers;

2) The proposed CMT will require ratepayers to pay for therms it does not consume;

3) The Nevada Commission also rejected the margin decoupling mechanism that was proposed in SWG's last rate case;

4) The issues of declining average usage, conservation, and fixed vs. variable costs all can be addressed without resorting to extreme measures such as the CMT.

Q. Please respond to SWG's rebuttal comments regarding RUCO's position that the proposed CMT is biased because it would only apply to residential customers.

A. The Company first argues that it is appropriate to apply the CMT to only the residential class because it is the largest class and has experienced the largest decline in average usage when compared to the other classes.

Q. Is this a valid reason for applying the proposed CMT solely to the residential class?

A. No. It is biased to single out the residential class for this take or pay mechanism simply because they are the largest class and the class that has historically conserved the most. In effect, the CMT as proposed would have residential ratepayers pay a penalty for conserving and hold all other classes harmless.

Q. Please respond to SWG's rebuttal comments regarding RUCO's position that the CMT will require residential customers to pay for therms they haven't used.

A. The Company claims RUCO's position is incorrect because customers will not be required to pay the *cost of gas* for the therms they don't use. This is true - customers do not pay the actual cost of the gas commodity itself, if not consumed; however the CMT does require to customers to pay the margin commodity cost of each therm not used. Since SWG's total commodity rate is approximately 50% margin and 50% gas cost - the CMT will in fact require payment for therms not used.

Q. Have you reviewed SWG's rebuttal arguments to your observation that the Nevada Commission rejected SWG's request for a CMT mechanism in that jurisdiction?

A. Yes. The Company argues that while the Nevada Commission did in fact reject a CMT mechanism in its recent rate case, the Nevada Commission did acknowledge the issue of declining usage by authorizing a rate design that allowed SWG to recover a significant portion of its fixed costs through the first consumption block. The Company claims that RUCO however has proposed a rate design that requires "a even greater amount of its margin recovery in the volumetric portion of its rates."

Q. Is this true?

A. No. In fact, the opposite is true. RUCO's recommended rate design shifts a significant amount of revenue recovery from the commodity charge to the fixed monthly service charge for both the residential and commercial classes. At page 33 of my direct testimony I discuss the modifications that RUCO has made to SWG's existing rate design, one of which is to shift revenue recovery from commodity rates to the fixed monthly service charge. The chart below compares the percentage of fix cost recovery under existing rates vs. under RUCO's proposed rates:

	Existing Rates	RUCO Rates
Residential Fixed	37.42%	41.16%
Commercial Fixed	24.65%	32.05%
Total Fixed	33.23%	38.17%

This shift in commodity revenue to fixed revenue lessens SWG's risk of not recovering its revenue requirement when usage is declining.

Q. How does SWG respond to your direct testimony at page 31 where you state that it is not necessary to resort to extreme and unprecedented measures such as the CMT to answer the Company's revenue recovery concerns?

A. The Company states at page 13 of Edward Gieseking's surrebuttal testimony that there are other alternatives to the CMT that would address SWG's fixed cost recovery concern. SWG suggests that the portion of costs recovered through the monthly service charge could be increased and a larger portion of the commodity charge could be assigned to the first block.

Q. Do you agree that these are appropriate methods of addressing the Company's fixed cost recovery concerns?

A. Yes, and interestingly enough, these are the exact two modifications that RUCO has recommended in its proposed rates. As discussed earlier, I have shifted revenue from the existing commodity rates to the fixed monthly service charge and flattened the commodity rate to one block so that all commodity revenue recovery will be realized in the first block. Thus, RUCO's recommended rate design adheres to SWG's proposed alternatives to the CMT.

Q. Why then does the Company continue to oppose your recommended rate design?

A. I do not know, since RUCO's recommended rate design comports with the alternatives suggested by SWG in its surrebuttal testimony.

Q. Do any of the Company's rebuttal comments change your position on the proposed CMT as set forth in your direct testimony?

A. No. The Company has not presented any new arguments or evidence that would cause RUCO to support such a mechanism.

RATE DESIGN

Q. Have you reviewed SWG's rebuttal testimony regarding rate design?

A. Yes. SWG witness Brooks Congdon provides the rebuttal testimony regarding rate design.

Q. Are there any areas of agreement between the Company and RUCO regarding rate design?

A. Yes. RUCO and the Company are in agreement regarding the following aspects of SWG's proposed rate design:

* Implementation of a new multi-family rate schedule
* Modification of the low-income rate schedule to year-round
* Elimination of rate schedule G-15
* Modifications to sub-classes within General Service

Q. Please discuss the Company's rebuttal comments regarding RUCO's proposed allocation of margin rates.

A. The Company claims that RUCO's proposed rate design shifts approximately $10 million of SWG's proposed margin from residential to general service customers and that RUCO's imputed billing determinants are improperly allocated.

Q. Please address these claims.

A. SWG's first claim has no relevance. SWG's proposed rates do not exist and at this time are merely a request. Since neither residential or non-residential customers are paying the proposed rates it would be impossible to shift revenue that does not exist. What is relevant is that RUCO's proposed rate design leaves intact the existing allocation of revenue between residential and non-residential rate classes. Current rates generate 67.16% of revenues from the residential class and RUCO's proposed rates also generate 67.16% of revenues from the residential class. The only shifting of revenue RUCO has proposed is from commodity rates *within* each class to the fixed monthly charge, which was done in response to SWG's concerns regarding fixed vs. variable costs.

The Company's second claim regarding RUCO's imputed billing determinants is discussed in depth in the surrebuttal testimony of Rodney Moore.

DEMAND SIDE MANAGEMENT PROGRAMS

Q. Have you reviewed the Company's rebuttal testimony regarding Demand Side Management?

A. Yes. The Company states that it generally supports RUCO's recommendations regarding DSM programs and funding. SWG agrees with a collaborative process for the development, administration, and performance assessment of the DSM programs.

Q. Does SWG have any negative reactions to RUCO's DSM recommendations?

A. No, not per se. However, the Company's rebuttal does discuss an "inherent financial disincentive" it has to aggressively promote energy efficiency programs and argues that its proposed CMT mechanism would mitigate this financial disincentive.

Q. Is it appropriate to allow SWG to implement a mechanism that would require customers to pay the margin cost of therms they don't use so as to incent SWG to promote energy efficiency?

A. No. The fact that the programs will be funded by ratepayers and approved by the Commission should provide adequate incentive for SWG to promote energy efficiency. Further, like any changes that occur in revenues, expenses, investment levels, and cost of capital, changes in customer usage can be addressed in a rate case that at the same time considers all ratemaking elements.

RATE BASE

Rate Base Adjustment # 2 - Pipe Replacement

Q. Please discuss the Company's rebuttal comments concerning your pipe replacement adjustment.

A. In the rebuttal testimony of Robert Mashas, the Company argues its proposed change in the required percentage write offs of defective pipe should be retroactively applied to all pipe replacements made subsequent to the end of the test year (December 31, 2000) in the last case.

Q. What is the Company's rationale for arguing for retroactive application of its proposed pipe replacement adjustment?

A. The Company argues that the Commission has the authority in a current rate case to determine the ratemaking treatment of any asset that is put in place during the period since the last rate case.

Q. Do you agree?

A. Yes. To the extent that a utility puts in place assets during the normal course of business, the Commission would typically look at those assets in the utility's next rate case and determine the appropriate ratemaking treatment. However, the typical treatment of plant additions between rate cases is not applicable to the pipe replacements at issue here. More than ten years ago in Decision No. 58693 the Commission determined the ratemaking treatment for the specific pipe replacements that are at issue here. While the Company is free to request that the Commission modify the requirements of Decision No. 58693 on a going forward basis (RUCO supports this prospective modification), the application of such a modification to a period prior to the Commission's adoption would result in retroactive ratemaking.

OPERATING INCOME

Operating Adjustment #8 - Compliance with Sarbanes Oxley Act

Q. Please discuss the Company's rebuttal comments concerning your Sarbanes Oxley adjustment.

A. SWG witness Randi Aldridge testifies that she agrees with RUCO's Sarbanes Oxley adjustment. However, she does not agree with RUCO that there is a double count in the Company's calculation of the Sarbanes Oxley implementation costs.

Q. Does the Company explain why it believes it has not double counted some of the test year Sarbanes Oxley costs?

A. No. The testimony of Ms. Aldridge merely declares there is no double count.

Q. Does it continue to be your position that the Company has double counted some of the test year Sarbanes Oxley costs?

A. Yes. Specifically, the Jefferson Wells invoices and the Ernst & Young invoices identified in the rebuttal testimony of Randi Aldridge, Exhibit No. RLA-2, page 2, lines 1 through 5 have been double counted in the Company's rate application. These invoices are included once in the test year recorded expenses in accounts 921 and 923. The same invoices are reflected again as part of the Company's requested deferrals of Sarbanes Oxley expenses.

Operating Adjustment #12 - Transmission Integrity Management Program

Q. What position does the Company take regarding your recommended adjustment for the Transmission Integrity Management Program (TRIMP)?

A. Company witness Robert Mashas states in his rebuttal testimony that RUCO's recommended TRIMP adjustment is reasonable and that SWG accepts both the amount of the adjustment as well as the seven year amortization proposed by RUCO.

Operating Adjustment #20 - Management Incentive Plan

Q. Please discuss the Company's rebuttal comments concerning your recommended disallowance of 67% of the cost of SWG's Management Incentive Plan (MIP).

A. The Company argues that each of the factors on which the MIP is based are in the interest of both stockholders *and* ratepayers, and therefore concludes that the cost of the MIP should be allocated 100% to ratepayers.

Q. What arguments does the Company present in support of this conclusion?

A. First, SWG argues that an improved customer to employee ratio benefits customers by increasing productivity, which in turn reduces costs. Second, SWG argues that achievement of the ROE targets and the success of the Company's management in controlling costs benefits ratepayers through an improved capital structure and a lowering of its cost of capital.

Q. Do you believe these arguments justify allocation of 100% of the MIP cost to ratepayers?

A. No. First, any gains in productivity or cost containment measures go straight to shareholders between rate cases. Further, I have yet to see a SWG rate case filing asking for a rate *decrease* as a result of successful productivity gains and cost containment efforts. Second, while an improved capital structure is certainly desirable and could positively impact the Company's cost of capital, historically this has not been the result.

Q. Please explain.

A. SWG has repeatedly paid annual MIP rewards for ROE achievement yet contrary to the Company's arguments in its rebuttal SWG's capital structure has not improved. The chart below shows SWG's actual capital structure for the last six years.

	Equity	Pref. Stock	Debt
1999	35.8%	4.3%	59.8%
2000	36.2%	4.1%	59.7%
2001	33.0%	3.5%	63.2%
2002	34.3%	3.5%	62.2%
2003	34.1%	5.4%	60.5%
2004	35.9%	5.0%	59.1%

At first blush SWG's rebuttal argument regarding the benefits that result from the achievement of the MIP's ROE goals may appear beguiling, however these arguments have no basis in reality. The MIP ROE rewards have been paid and there has been no improvement in the capital structure nor material change in the cost of debt since the Company's last rate case.

As just discussed, the arguments presented in the Company's rebuttal testimony do not support a conclusion that ratepayers should bear 100% of the cost of the MIP. Rather, the Company's arguments further support RUCO's position that costs should be shared 67%/33% between shareholders and ratepayers.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL

DOCKET NO. G-0155A-04-0876
SCHEDULE MDC-3

SURREBUTTAL

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	MATERIALS & SUPPLIES PER SWG	$9,222,489	SCH. B-5, PG. 3
2	MATERIALS & SUPPLIES PER RUCO	9,222,489	SCH. B-5, PG. 3
3	ADJUSTMENT	0	LINE 2 - LINE 1
4	PREPAYMENTS PER SWG	2,740,815	SCH. B-5, PG. 4
5	PREPAYMENTS PER RUCO	3,366,772	SCH. MDC-3, Pg 5
6	ADJUSTMENT	625,957	LINE 5 - LINE 4
7	CASH WORKING CAPITAL PER SWG	(11,082,156)	SCH. B-5, PG. 2
8	CASH WORKING CAPITAL PER RUCO	(13,632,469)	SCHEDULE MDC-3, Pg 2
9	ADJUSTMENT	(2,550,313)	LINE 8 - LINE 7
10	TOTAL ADJUSTMENT	($1,924,355)	SUM OF LINES 3, 6 & 9

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL

SURREBUTTAL

LINE NO.	DESCRIPTION	(A) EXPENSE PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
1	COST OF GAS	$298,559,015		298,559,015	43.78	13,070,913,677
2	LABOR COST	107,117,974	(4,234,725)	102,883,249	14.01	1,441,394,319
3	UNCOLLECTIBLE	1,498,151		1,498,151	120.00	179,778,120
4	OTHER O&M	45,068,143	(6,788,052)	38,280,091	31.05	1,188,451,696
5	INTEREST	40,521,530	(4,015,857)	36,505,673	87.34	3,188,405,450
6	TAXES OTHER THAN INCOME	33,455,124	(1,267,863)	32,187,261	206.50	6,646,669,500
7	INCOME TAXES	18,192,843	9,735,438	27,928,281	37.50	1,047,310,548
8	TOTAL OPERATING EXPENSES	544,412,780		537,841,721		26,762,923,310
9	EXPENSE LAG				49.76	
10	REVENUE LAG				40.62	
11	NET LAG				(9.14)	
12	CASH WORKING CAPITAL	($13,632,469)				

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL

DOCKET NO. G-0155A-04-0876
SCHEDULE MDC-3

SURREBUTTAL

LINE NO.	MID-POINT OF SERVICE PERIOD	PAYMENT DATE	PERCENT PAYMENT	(LEAD)/LAG DAYS	DOLLAR DAYS
1	7/1/2003	4/15/2003	25.00%	(77)	(19.25)
2	7/1/2003	6/15/2003	25.00%	(16)	(4.00)
3	7/1/2003	9/15/2003	25.00%	76	19.00
4	7/1/2003	12/15/2003	25.00%	167	41.75
5	7/1/2003	3/15/2004	0.00%	258	0.00
6	TOTALS		100.00%		37.50
7	INCOME TAX LAG			37.50	

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL

DOCKET NO. G-0155A-04-0876
SCHEDULE MDC-3

SURREBUTTAL

Line No.	Month	Cost	Lag Days	Dollar Days
	(a)	(b)	(c)	(d)
1	September 2003	$2,065,502	27.14	56,065,384
2	October 2003	2,281,209	24.19	55,183,873
3	November 2003	2,122,438	14.51	30,806,560
4	December 2003	2,799,950	19.45	54,459,832
5	January 2004	1,619,271	76.74	124,263,026
6	February 2004	1,310,710	46.31	60,700,671
7	March 2004	2,873,308	32.15	92,368,700
8	April 2004	1,937,390	17.71	34,308,766
9	May 2004	1,865,981	24.72	46,127,781
10	June 2004	2,515,719	48.84	122,871,846
11	July 2004	3,728,708	22.06	82,248,601
12	August 2004	2,172,721	40.47	87,936,239
13	Total	$27,292,907	31.05	847,341,280

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL

DOCKET NO. G-0155A-04-0876
SCHEDULE MDC-3
PAGE 5 OF 5

SURREBUTTAL

LINE NO.	MONTH	(A) BALANCE	(B) DEBITS	(C) CREDITS	(D) ADJUSTED BALANCE
1	AUGUST	$5,130,082			5,130,082
2	SEPTEMBER	4,798,680			4,798,680
3	OCTOBER	3,784,576	66,608	0	3,851,184
4	NOVEMBER	3,956,561	12,000	5,551	4,029,618
5	DECEMBER	5,938,689	119,223	6,551	6,124,419
6	JANUARY	5,258,062	697,011	16,486	6,124,317
7	FEBRUARY	4,984,761	958,218	74,570	6,734,664
8	MARCH	4,810,591	295,000	154,422	6,701,072
9	APRIL	4,204,986	408,228	179,005	6,324,690
10	MAY	4,296,987	153,500	213,024	6,357,167
11	JUNE	3,639,813	27,754	225,816	5,501,931
12	JULY	3,377,801	105,000	228,129	5,116,791
13	AUGUST	7,698,845	17,007	236,879	9,217,963
14	TOTAL	61,880,434			76,012,577
15	13 MONTH AVERAGE	$4,760,033		57.58%	$3,366,772

REFERENCES
COLUMN (A): SCH. B-5, PG. 4
COLUMN (B): SCH. B-5 W/P SHEET 30-59
COLUMN (C): COLUMN (B) PRIOR MOS. ACCRUALS / 12 MONTHS
COLUMN (D): PRIOR MONTH COLUMN (D) + CURRENT MONTH COLUMN (B) - CURRENT MONTH COLUMN (C) + CURRENT MONTH COLUMN (A) - PRIOR MONTH COLUMN (A)

EXHIBIT
RUCO-5
Admitted

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-04-0876

DIRECT TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 26, 2005

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name, position, employer and address.

A. Rodney L. Moore, Public Utilities Analyst V
Residential Utility Consumer Office ("RUCO")
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007.

Q. Please state your educational background and work experience.

A. I obtained a Bachelor's Degree in Business Administration in 1993 from Athabasca University. I have attended several training classes and courses regarding auditing, rate design, income taxes, and other utility related matters. From 1966 to 1993, I was employed by Telus Corporation, Inc., a large telecommunication company, where I assumed various positions from lineman to office administrator. In 1995, I began my employment with the Arizona Corporation Commission ("ACC" or "Commission"). I worked in the Consumer Service Section until accepting a position as an Auditor in October 1999 with the Accounting and Rates Section. In May of 2001, I succeeded to my current position at RUCO. My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding Southwest Gas Corporation's ("Company" or "SWG") application for a determination of the current fair value of its utility plant and property and for increases in its rates and charges based thereon for gas service. The test year utilized by the Company in connection with the preparation of this application is the 12-month period that ended August 31, 2004.

BACKGROUND

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's filing as it relates to operating income, rate base, the Company's overall revenue requirement and rate design. My recommendations are based on these analyses. Procedures performed include the in-house formulation and analysis of fifteen sets of data requests, the review and analysis of Company responses to Commission Staff data requests, conversations with Company personnel and the review of prior ACC dockets related to SWG.

The Commission in Decision No. 64172, dated October 30, 2001, approved the Company's present rates and charges for utility service. The test year used in that proceeding was the 12-month period ending December 31, 1999.

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Q. What areas will you address in your testimony?

A. I will address issues related to rate base, operating income, revenue requirements and rate design. RUCO's witness William A. Rigsby will provide an analysis of the cost of capital as presented on Schedule RLM-18. RUCO's witness Marylee Diaz Cortez will also address additional issues related to rate base, operating income, rate design and revenue requirements.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules numbered RLM-1 through RLM-18.

SUMMARY OF ADJUSTMENTS

Q. Please summarize the adjustments to rate base, operating income and rate design issues addressed in your testimony.

A. My testimony addresses the following issues:

Rate Base

<u>Fair Value Rate Base</u> – This adjustment states the fair value rate base by giving equal weighting (50/50 split) to RUCO's adjusted original cost rate base and RUCO's calculation of the reconstruction cost new depreciated rate base.

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Test-Year In Service Plant and Accumulated Depreciation – This adjustment restates gross test-year gas plant in service and the accumulated depreciation value to reflect RUCO's adjustments.

Operating Income

Labor Annualization Expense – This adjustment reduces test-year operating expenses to reflect RUCO's recommended level of annualized payroll and payroll taxes.

Uncollectibles Annualization Expense – No adjustment.

Promotional Expense – No adjustment.

American Gas Association Dues – This adjustment removes the portion of the dues dedicated to advertising and lobbying.

Paiute Allocation Annualization Expense – No adjustment.

Injuries and Damages Expense – This adjustment reflects RUCO's determination of an average annual level of expense.

Rate Case Expense – RUCO is proposing no adjustment at this time, but reserves the right to make an adjustment to the rate case expenses after an assessment of actual costs is made.

Miscellaneous Expense – RUCO expanded the scope of the Company's proposed adjustment to miscellaneous expense adjustments and removed inappropriate expenditures not necessary in the provisioning of gas service.

Vehicle Compensation Expense – No adjustment.

Out of Period Expense – No adjustment.

Property Taxes Expense - This adjustment reflects the appropriate level of property tax expense given RUCO's recommended level of net plant in service.

Interest on Customer Deposits expense – No adjustment.

RUCO Adjustments To Test-Year Operating Expenses – This adjustment reflects RUCO's determination to remove the supplemental executive retirement plan.

Income Tax Expense – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

Rate Design

In the instant case, I was responsible to produce an accurate set of bill determinants. Therefore, I revised the bill determinants to reflect updated bill frequency analyses provided by the Company and RUCO's adjustment to correctly produce test-year revenues. I then imputed revised bill determinants into the Company's proposed rate design; and finally annualized the imputed bill determinants utilizing the Company's pro forma adjustments. Ms. Marylee Diaz Cortez will discuss RUCO's proposed rate design in her testimony.

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REVENUE REQUIREMENTS

Q. Please summarize the results of your analysis of the Company's filing and state RUCO's recommended revenue requirement.

A. As outlined in Schedule RLM-1, I am recommending that the Company's revenue requirement not exceed:

SWG	RUCO	DIFFERENCE
\$393,675,106	\$370,818,589	(\$22,856,517)

My recommended decrease in Fair Value Rate Base ("FVRB") based on the equal weighting of a 50/50 split between Original Cost Rate Base ("OCRB") and Reconstruction Cost New Depreciated Rate Base ("RCND") is summarized on Schedule RLM-1:

SWG	RUCO	DIFFERENCE
\$1,171,427,301	\$1,163,910,949	(\$7,516,352)

The detail supporting my recommended rate base is presented on Schedules RLM-2, RLM-3, RLM-4, and RLM-5.

My recommended increase in required operating income is shown on Schedule RLM-1 as:

SWG	RUCO	DIFFERENCE
\$86,957,942	\$79,378,637	(\$7,579,305)

My recommended revenue requirement percentage increase versus the Company's proposal is as follows:

SWG	RUCO	DIFFERENCE
21.93 %	14.85 %	-7.08 %

Schedule RLM-1 presents the calculation of my recommended revenue requirement.

RATE BASE

Rate Base Adjustment No. 1 – Fair Value Rate Base

Q. Please explain the basis for your determination of the fair value rate base ("FVRB").

A. RUCO's determination of the FVRB consists of three elements. First, as shown on RLM-2, the value of the OCRB was restated to reflect RUCO's adjustment to the various rate base determinants. Second, as shown on RLM-4, the value of the RCND was computed. Third, as shown of RLM-1, the FVRB was computed on an equally weighted basis (50/50 split) between RUCO's OCRB and RCND.

Q. Please elaborate on the first element of RUCO's FVRB determination.

A. The first element consists of several adjustments to the OCRB. The aggregate adjustment was corroborated between myself and RUCO witness Marylee Diaz Cortez. As shown on RLM-3, I was responsible for analyzing the Construction Completed Not Classified ("CCNC"), while Ms. Cortez calculated the remaining adjustments.

The CCNC was adjusted to reflect information received from the Company in its response to RUCO data request number 13. I only considered CCNC projects that were placed in service within the test year. Moreover, I also reduced the test year gross plant in service by removing the retired plant associated with the appropriate CCNC projects.

My adjustment to CCNC is shown on supporting Schedule RLM-4. Please see Ms. Diaz Cortez testimony for explanation of the other rate base adjustments on Schedule RLM-3.

Q. Please elaborate on the second element of RUCO's FVRB determination.

A. The second element is the computation of the RCND. RUCO's RCND was computed by multiplying RUCO's OCRB by the percentage difference between the Company's OCRB and its RCND as filed.

Q. Please elaborate on the third element of RUCO's FVRB determination.

A. The third element is the computation of the FVRB. RUCO computed the FVRB by calculating a 50/50 split between RUCO's OCRB and its RCND.

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This adjustment to fair value rate base decreased the test-year rate base by:

$6,765,240.

OPERATING INCOME

Operating Income Summary

Q. Is RUCO recommending any changes to the Company's proposed operating expenses?

A. Yes. As shown on Schedule RLM-7, pages 1 through 2, columns (B) through (Q), RUCO analyzed the Company's nineteen adjustments to its historical test-year operating income and made several adjustments to the operating income as filed by the Company. RUCO witness Ms. Cortez testimony discusses seven of the adjustments, while I was responsible for reviewing twelve of the adjustments the Company proposes to its test-year operating income, and finally, through discovery, RUCO recommends other adjustments. My review, analysis and adjustments are explained below.

SWG Operating Income Adjustment No. 3 – Labor Annualization

Q. Please discuss the Company's proposed labor expense adjustment.

A. The Company has proposed an adjustment that increases historical test - year labor and labor loading expense by $1,638,419.

. . .

Q. What elements did the Company include in this labor annualization adjustment number 3?

A. In the aggregate amount of adjustment number 3, the Company considered all the determinants of labor and labor loading expenses, which impact the total labor costs of SWG's.

Q. What elements did you include in your adjustment to the Company's adjustment number 3?

A. My adjustments to the Company adjustment number 3 only reflect labor costs and the payroll taxes. For clarification purposes, other adjustments to SWG's annualized labor expenses are discussed later in RUCO testimony and separately supported under Schedule RLM-14.

Q. What are the elements of the Company's proposed labor expense adjustment?

A. The Company's proposed adjustment is comprised of the following elements:

1. Annualization of employees' salaries and wages as of the August 31, 2004 test-year-end;
2. Increase in the test-year-end annualized salaries to reflect a projected 2005 wage and salary increase of 2.00%;
3. Increase in the test-year-end annualized wages and salaries to reflect a projected 1.35% "within grade" salary and wage increase;

4. Use of the test-year overtime percentage to reflect the estimated proforma overtime expense; and

5. Use of the historical test-year O&M ratio to estimate the level of proforma O&M labor expense.

Q. Please discuss the first of these elements.

A. On June 28, of the 2004 test year, SWG's employees received a 2.00% wage increase. In its proforma labor adjustment the Company has annualized the August 2004 labor (which includes the 2.00% increase) to reflect the level of wages that would be incurred had the wage increase been in effect during the entire test year.

Q. Do you agree with this portion of the Company's proposed labor expense adjustment?

A. Yes. Since an end-of-test-year rate base is used in Arizona, the Commission has typically allowed adjustments that annualize revenues and expenses to year-end levels. Such annualizations serve to create a matching between rate base, revenues and expenses, and in the absence of extenuating circumstances, are generally appropriate. The end result of the Company's annualization adjustment is to reflect the level of wages that was in effect at August 31, 2004.

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Q. Please discuss the next element of the Company's proposed labor adjustment.

A. The Company has further increased the already annualized level of labor by an additional 2.00% to reflect a projected increase slated for June 2005.

Q. Do you agree with this portion of the Company's proposed adjustment?

A. No. The Company has already made an adjustment that annualizes the test-year-end level of salaries and wages. That annualization already serves to match rate base, revenues, and expenses. The inclusion of an additional 2.00% wage increase for 2005 would result in the use of selective projected expenses. Biased rates will result if the Company is allowed to pick and chose which rate base, expense, and revenue items it will reflect on an actual, projected or annualized basis.

Q. Are there any other reasons why the additional 2.00% wage increase proposed by the Company is inappropriate?

A. Yes. If the additional 2005 projected 2.00% wage increase were allowed, it would result in a doubling up of expenses during the test year. SWG historically has granted one wage increase per year. If the Company's proposed year-end annualization *and* the Company's proposed 2005 wage increase are both allowed the test year will contain two labor increases.

Since the Company only awards one wage increase per year this would result in a double count.

Q. Please discuss the third element of the Company's proposed labor adjustment.

A. The Company has increased the test-year-end annualized level of labor to reflect an additional 1.35% increase related to "within grade" increases.

Q. What is a "within grade" increase?

A. Each non-exempt employee position is graded. Within each grade are a number of levels through which employees pass as they meet certain performance and time criteria within the grade. Each level carries a fixed wage increase.

Q. Do you agree with this portion of the Company's proposed adjustment?

A. No. As just discussed, the Company has already annualized its test year labor to reflect the year-end level of labor. Thus, any "within grade" wage increases granted through the end of the test year are already included in the Company's proposed labor by virtue of the Company's annualization adjustment. Inclusion of an additional 1.35% increase would have the effect of double counting the test year "within grade" increases.

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Q. Please discuss the fourth element of the Company's proposed labor adjustment.

A. The Company has increased its annualized level of labor expense by 8.53% (Arizona), 2.77% (Corporate Direct), and 0.43% (System Allocable), which represent the test-year overtime percentage.

Q. Do you agree with this portion of the Company's adjustment?

A. I agree that it is appropriate to include the historical level of overtime in the annualized level of labor. However, the manner in which the Company has calculated the annualized level of overtime results in an overstatement of overtime labor expense.

Q. Please explain.

A. The Company calculated its test year annualized labor by taking each employee position's salary and wages as of August 31, 2004 and annualizing that amount to reflect 12 months of that level of earnings. In response to RUCO data request 2.08 the Company provided the underlying data that supports that calculation. Pursuant to my review of that information I became aware that the annualized salaries calculated by the Company included both base wages *and* incentive compensation that was paid to certain sales and marketing personal. Thus, when the Company applies the historical overtime percentage to the total annualized labor it has the effect of attributing additional overtime dollars to the salaries of the sales and marketing personal. Payroll dollars related to SWG's marketing and sales employee should be disallowed as a rate case expense.

Q. Does SWG incur any payroll expense related to sales, marketing, and promotional activities?

A. Yes. Specifically, SWG has 37 employees who fill positions whose primary responsibilities include the marketing of gas and gas products.

Q. Please explain the Company's adjustment to the Sales and Marketing Payroll expense.

A. The Company has made adjustment number 6 that decreases test-year expenses by $552,091 to remove certain marketing, selling, and promotional expenses that have been disallowed in prior SWG rate cases. The costs removed relate only to third party vendors and do not include any payroll dollars related to SWG employees' marketing, sales and promotional efforts.

Q. Are the duties and responsibilities of these positions the type of activities the Commission has excluded from rates in the past?

A. Yes. The Commission has previously disallowed the cost of sales, marketing and promotional activities. As previously mentioned, the Company has removed over a half million dollars in marketing and promotional costs in this rate application. In its testimony and in response to data requests SWG acknowledges that marketing and promotional activities traditionally have not been included as a component of rates. However, despite this acknowledgement the Company has failed to remove its in-house payroll associated with these activities.

Q. Who realizes the initial benefit from any increases in load resulting from these sales and marketing activities?

A. Any additional margin realized through these sales and marketing efforts accrues to shareholders between rate cases. Until such additional load is recognized in rates the only beneficiary is the stockholder.

Q. Should ratepayers be required the bear the cost of these sales, marketing, and promotional activities?

A. No. The Commission has already recognized that these type of costs need to be contained. It has also recognized that ratepayers should not be forced to fund an escalating competition between the electric and gas industry. Furthermore, initially any increased sales arising out of these marketing efforts accrue solely to shareholders. Ratepayers should not be required fund the cost of the Company's marketing and promotional activities. Accordingly, as shown on RLM-8, page 7, line 44, I have removed $2,892,434 from my recommended annualized payroll calculation.

Q. Please discuss the fifth element of the Company's labor adjustment.

A. The Company has used the test-year O&M ratio to determine the portion of the proforma labor that is expense and the portion that is capitalized.

Q. Do you agree with this element of the Company's proposed labor adjustment.

A. Yes. The test-year O&M ratio forms a reasonable basis for estimating the level of proforma labor that will be expensed. RUCO has no objection to the use of the test-year O&M ratio.

Q. Please summarize the specific adjustments you have made to the Company's proposed labor expense.

A. I have made the following adjustments:

1. Removed the projected 2005 wage and salary increase of 2.00%. The Company's annualization adjustment already includes the test-year labor increases;
2. Removed the projected post-test-year "within grade" wage increases. The test year has already been annualized to reflect the level of salaries and wages, including "within grade" increases, as of the test year end; and
3. Removed from the test-year annualized labor the amount related to sales and marketing payroll costs.

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Since the Commission has previously disallowed the cost of sales, marketing and promotional activities.

Q. What are the elements of the Company's proposed labor loading expense adjustment?

A. The Company's proposed adjustment is comprised of the following elements:

1. Annualization of FICA, FUTA, SUTA and Medicare expenses;
2. Increase other employee benefits based on the annualized salaries and annualized employee levels; and
3. Remove expenses related to employee gifts, events and awards in compliance with Commission Decision No. 64172, dated October 30, 2001.

Q. Which of the Company's labor loading elements did you review and analyze for this adjustment?

A. In this adjustment I only considered the first element of the Company's adjustment to labor loading. The Company's second and third labor loading elements will be discussed later in my testimony.

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Q. What adjustments did you make to the Company's FICA, FUTA, SUTA and Medicare payroll taxes?

A. I adjusted the Company's FICA, FUTA, SUTA and Medicare payroll taxes to correspond to RUCO's recommended level of labor.

Q. Please explain how you quantified the necessary adjustment.

A. As shown on Schedule RLM-8, page 4, I multiplied RUCO's recommended level of labor by the statutory FICA, FUTA, SUTA and Medicare rates. Through this calculation I determined the necessary level of payroll taxes. To this amount I applied the Company's test year O&M ratio to determine the portion of the payroll taxes that will be recorded to expense. As shown on Line 30 of Schedule RLM-8, page 4, it is necessary to decrease the proforma level of FICA, FUTA, SUTA and Medicare payroll taxes by $575,452 to correspond to RUCO's recommended level of payroll expense.

This total adjustment to labor and labor loading decreased test-year expenses by:

$4,235,547.

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SWG Operating Income Adjustment No. 5 – Uncollectibles Annualization

Q. Please explain your analysis to annualize the Company's uncollectibles expense in account number 904.

A. The Company has adjusted its test-year uncollectibles expense based on its test-year adjusted level of revenues. Because I am not proposing any test-year revenue adjustments, likewise no adjustment is necessary to uncollectibles expense.

SWG Operating Income Adjustment No. 6 – Promotional Expenses

Q. Please explain the Company's proposed adjustment to the promotional expenses.

A. The Company removes expenses related to promotional marketing and advertising programs from the cost of service that have not been allowed.

SWG Operating Income Adjustment No. 7 – American Gas Association ("AGA") Dues

Q. During the test year did the Company pay dues to the American Gas Association?

A. Yes. SWG paid $384,566 for its membership with the AGA during the test year.

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Q. What is the AGA?

A. The AGA is a national trade association for natural gas distribution and transmission companies.

Q. Has RUCO proposed an adjustment to remove a portion of the AGA dues paid during the test year from cost of service?

A. Yes. In the Company's response to RUCO data request number 14.2 documentation was provided from the AGA/NARUC Oversight Committee Staff Agreement, which identifies each category of AGA expenditures and the percentage of the AGA's annual expenditures that were devoted to each category.

Q. Which categories of AGA activities should not be funded by ratepayers?

A. The AGA spent approximately 16% of its budget in the Communications category, which promotes the use of gas over other fuels. In the Company's adjustment number 6, SWG recognized the Commission has determined that these types of costs should not be borne by ratepayers and therefore has removed similar expenses from this application.

Q. Are there any other categories of AGA expenditures that should not be borne by ratepayers?

A. Yes. The Public Affairs category of expenditures should not be borne by ratepayers, because this provides members with information on legislative and regulatory developments; prepares testimony, comments, and filings regarding legislative and regulatory activities; lobbies on behalf of the industry.

Q. Why should this category of expenditures of the AGA be excluded from rates?

A. The category of Public Affairs should be excluded because it is utilized to represent the legislative interests of gas company stockholders. Further, lobbying expenses are typically reflected as below-the-line expenditures and not included in rates.

Q. What adjustment have you made?

A. As shown on Schedule RLM-9, I have removed 39.09% of the Arizona allocated portion of SWG's test year AGA dues. This represents the percentage of the AGA's expenditures that was used for advertising and lobbying.

This adjustment reduces operating expenses by:

$75,385.

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SWG Operating Income Adjustment No. 9 – Paiute Allocation Annualization

Q. Please explain your analysis to annualize the Company's Paiute Allocation in accounts numbered 920 and 930.

A. After review of the Company's Schedule C-2, Adjustment No. 9, I made no adjustment.

SWG Operating Income Adjustment No. 10 – Injuries and Damages

Q. Please explain your adjustment to the Company's injury and damage expenses.

A. The adjustment consists to two elements. First, the Company normalizes its self-insured retention costs, and second, the Company annualizes its liability insurance premiums.

Q. Please explain the first element of this adjustment to normalize the Company's estimated self-insured expense.

A. The Company proposes to use a fourteen-year average of actual claims paid to establish a level of self-insured expense.

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Q. Is there a problem with the Company's proposal to use of the fourteen-year average of actual claims paid to establish a level of self-insured expense?

A. Yes. Since the maximum deductible is now $10 million, I reduced the 1993 $18.8 million dollar claim to $10 million to reflect the new parameters.

Q. Please explain the second element of your analysis of the Company's adjustments to test-year liability insurance premiums.

A. After review of the Company's computations to amortize the liability insurance premiums on Schedule C-2, adjustment number 10, sheet 2, I made no changes to this portion of SWG's adjustment.

This total adjustment decreased test-year expenses by: $346,404.

<u>SWG Operating Income Adjustment No. 13 – Rate Case Expense</u>

Q. Please explain your review of the Company's proposed rate case expenses in account number 328.

A. Through the Company's response to RUCO data request 14.4 I have obtained copies of rate case billings to date, the total amount actually incurred is not yet known. Thus, the accuracy and reasonableness of the Company's estimated level of expense cannot be determined. As a result, at this time I am not proposing an adjustment to the rate case expense. RUCO however, reserves the right to change its position as more information becomes available.

<u>SWG Operating Income Adjustment No. 14 – Miscellaneous Expenses</u>

Q. Please explain your analysis of the Company's proposed adjustment to remove certain costs from test year expenses that the Company deems inappropriate to recover from these proceedings.

A After review of the Company's workpapers and its response to RUCO data requests numbered 5, 6, 8, 11, 12 and 14, I determined there were numerous similar type of expenditures not removed by the Company in its adjustment number 14.

Therefore, as shown on Schedule RLM-12, RUCO has made an additional adjustment to more accurately reflect the removal of test-year expenses related to payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events and for various meals, lodging and refreshments, which are not necessary in the provisioning of gas service. Back-up documentation denoting each individual expense removed is recorded in my Workpaper Schedules: RLM-11WP(870) Pages 1 To 4, RLM-11WP(880) Pages 1 To 18, and RLM-11WP(902) Pages 1 To 3.

. . .

This adjustment decreased test-year expenses by:

$346,299.

SWG Operating Income Adjustment No. 15 – Vehicle Compensation

Q. Please explain your analysis of the Company's adjustment to vehicle compensation expenses.

A. After review of the Company's calculation to remove the amount of test year expenses included in employee income for the personal use of Company vehicles, I made no adjustment.

SWG Operating Income Adjustment No. 16 – Out of Period Expenses

Q. Please explain your analysis of the Company's removal of out of period expenses.

A. After review of the Company's Schedule C-2, adjustment number 16, I made no adjustment.

SWG Operating Income Adjustment No. 18 – Property Tax

Q. Do you agree with SWG's methodology for computing gas utility property taxes?

A. Yes. I have used the same methodology to compute RUCO's recommended level of property taxes.

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. . .

This calculation is shown on Schedule RLM-13, the difference in the amount I have calculated versus the Company is solely a result of our respective levels of recommended net plant in service and our respective treatment of Contributions in Aid of Construction..

This adjustment decreased test-year expenses by: $1,267,863.

<u>SWG Operating Income Adjustment No. 19 – Interest on Customer Deposits</u>

Q. Please explain your analysis of the Company's adjustment to the interest on customer deposits expense.

A. After review of the Company's Schedule C-2, adjustment number 19, I made no adjustment.

<u>Operating Income Adjustment No. 20 – RUCO Adjustments To Operating Expenses</u>

Q. Please explain the basis for the additional adjustments you made to the operating expenses.

A. For clarification purposes, I made separate adjustments to the Company's adjustment number 3.

. . .

. . .

These adjustments highlight specific issues embedded in SWG's payroll, which are included in the labor and labor loading costs and should not be the sole financial burden of the ratepayers.

Q. What specific adjustment do you recommend?

A. I made an adjustment to Supplemental Executive Retirement Plan costs.

Q. Please explain your adjustment to the Supplemental Executive Retirement Plan.

A. The Company's test-year payroll loadings include the cost of a Supplemental Executive Retirement Plan ("SERP"). The Company's test year operating expenses include approximately $2.7 million related to the SERP. The SERP is a retirement plan that is provided to a small select group of high-ranking officers of the Company. The high-ranking officers who are covered under the SERP receive these benefits in addition to the regular retirement plan.

Q. Should ratepayers be required to pay the cost of supplemental benefits for the high-ranking officers of the Company?

A. No. The cost of supplemental benefits for high-ranking officers is not a necessary cost of providing gas service. These individuals are already fairly compensated for their work and are provided with a wide array of benefits including a medical plan, dental plan, life insurance, long term disability, paid absence time, and a retirement plan. If the Company feels it is necessary to provide additional perks to a select group of employees it should do so at its own expense.

Q. In SWG's recent Nevada rate case, what did the Nevada Commission rule regarding SERP?

A. The Nevada Commission agrees SERP should be excluded from operating expenses; SWG has not presented any documentation or evidence to detail or support its SERP as reasonable.

Q. What adjustment are you recommending?

A. As shown on Schedule RLM-14, I have removed the test year cost of the SERP from operating expenses. This adjustment decreases operating expenses by $1,566,073.

RATE DESIGN

Q. Please explain your contribution to RUCO's recommended rate designs.

A. I was responsible to produce an accurate set of bill determinants (i.e. test-year customer bill counts and therms consumed). I revised the bill determinants to reflect an updated bill frequency analysis provide by the Company in its response to RUCO data request 9.01. I made further adjustments to correctly produce test-year revenues from these revised determinants. I then imputed the revised bill determinants into the

Company's proposed rate design; and finally annualized the imputed bill determinants by utilizing the Company's pro forma adjustments. Ms. Marylee Diaz Cortez will discuss RUCO's proposed rate design and structure in her testimony.

Q. Have you prepared a Schedule presenting your recommended bill determinants?

A. Yes, I have. My recommended bill determinants are an integral part of the rate design presented on Schedule RLM-16, pages 1 through 3.

PROOF OF RECOMMENDED REVENUE

Q. Have you prepared a Schedule presenting proof of your recommended revenue?

A. Yes, I have. Proof that RUCO's recommended rate designs will produce the recommended required revenue as illustrated, is presented on Schedule RLM-16, page 3.

TYPICAL BILL ANALYSIS

Q. Have you prepared a Schedule representing the financial impact of RUCO's recommended rate design on the typical residential customer?

A. Yes, I have. A typical bill analysis for a metered residential customer is presented on Schedule RLM-17.

. . .

Q. Please explain elements of your typical bill analysis.

A. Schedule RLM-17 illustrates the elements proposed by Ms. Diaz Cortez in her testimony, which are:

1. Shift a portion of the revenue requirement that is currently recovered from the commodity rates to the fixed monthly charges;
2. Flatten the current declining tier commodity rate structure to one uniform commodity rate for all usage; and
3. Eliminate the summer and winter rate structure differential.

Q. Please provide an excerpt of RUCO's rate structure that illustrates these fundamental changes in SWG's current rate design.

A. Schedule RLM-17 provides an extensive breakdown of the effects of RUCO's proposed rates on the G-5 Residential Customer. Below is a chart gleaned from Schedule RLM-17 comparing SWG's present winter rates to RUCO's proposed annual rates:

<u>SWG Present Rates and Charges</u>

Basic Monthly Service Charge	$8.00
Commodity Charges (including both margin and a gas cost of $0.5346):	
Winter (October to May)	
First Tier (Up to 40 Therms)	$1.02198
Second Tier (Over 40 Therms)	$0.93780

. . .

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. . .

RUCO Proposed Rates and Charges

Basic Monthly Service Charge $9.36

Commodity Charges All Usage (including both margin and a gas cost of $0.5346) $1.021545

Description	Therms	Present	Proposed	$ Increase	% Increase
25% Average	11	$19.46	$20.81	$1.36	6.97%
75% Average	34	$42.37	$43.71	$1.35	3.18%
Average Usage	45	$53.41	$55.16	$1.75	3.27%
150% Average	67	$74.44	$78.06	$3.63	4.87%
200% Average	90	$95.46	$100.96	$5.50	5.76%

Q. Please indicate how this chart illustrates the first goal of RUCO's proposed rates.

A. As shown by the percentage increase of 6.97% for the minimal consumption customers (consuming only 25% of the average customer), this is the greatest percentage increase of all analyzed groups. This indicates a shift of the allocation of revenue from the variable usage component to the fixed basic service charge. This shift will afford the Company a better opportunity to recover its costs.

Q. Please indicate how this chart illustrates the second and third goals of RUCO's proposed rates.

A. As shown in RUCO's proposed rates and charges, the commodity charges have been simplified by recommending one year-round uniform commodity rate. This uniform rate eliminates the summer/winter differential and insures all customers within each rate structure will pay the same amount for each therm consumed. This uniform rate promotes SWG's corporate objective for energy efficient consumption over the Company's proposed declining rate. Moreover, as illustrated by the incrementally greater percentage increase for the higher consumers (i.e. 4.87% for consumption at 150% of average and 5.78% for consumption at 200%) provides a positive price signal to encourage energy efficient usage.

COST OF CAPITAL

Q. Is RUCO proposing any adjustments to the Company proposed cost of capital?

A. Yes, it is. This adjustment decreases the Company's cost of common equity and therefore its weighted cost of capital by 76 basis points from 9.40 to 8.64 percent to reflect current market conditions. This adjustment is fully explained in the testimony of RUCO witness William A. Rigsby.

CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations.

A. I conclude that the approval of this application will be consistent with the public interest if the Commission adopts the following recommendations:

1. For ratemaking purposes, the proposed revenue requirements should not exceed $370,818,589.

2. For ratemaking purposes, the FVRB for test year ending August 31, 2004 should be $1,163,910,949.

3. A fair and reasonable rate of return on FVRB is 6.82 percent.

4. Deny the Company's request for a CMT as a residential margin decoupling mechanism and in its stead utilize the rate structure as recommended by RUCO.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Southwest Gas Corporation
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Test Year Ended August 31, 2004

TABLE OF CONTENTS TO RUCO SCHEDULES

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REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 925,212,447	$ 1,417,642,156	$ 1,171,427,301	$ 918,447,207	$ 1,409,374,691	$ 1,163,910,949
2	Adjusted Operating Income (Loss)	$ 44,233,345	$ 44,233,345	$ 44,233,345	$ 50,445,135	$ 50,445,135	$ 50,445,135
3	Current Rate Of Return (Line 2 / Line 1)	4.78%	3.12%	3.78%	5.49%	3.58%	4.33%
4	Required Operating Income (Line 5 X Line 1)	$ 86,957,942	$ 86,957,942	$ 86,957,942	$ 79,378,637	$ 79,378,637	$ 79,378,637
5	Required Rate Of Return	9.40%	6.13%	7.42%	8.64%	5.63%	6.82%
6	Operating Income Deficiency (Line 4 - Line 2)			$ 42,724,598	$ 28,933,501		$ 28,933,501
7	Gross Revenue Conversion Factor (Schedule RLM-1, Page 2)			1.6573			1.6573
8	Increase In Gross Revenue Requirement (Line 7 X Line 6)			$ 70,809,128			$ 47,952,611
9	Adjusted Test Year Revenue			$ 322,865,978			$ 322,865,978
10	Proposed Annual Revenue Requirement (Line 8 + Line 9)			$ 393,675,106			$ 370,818,589
11	Required Percentage Increase In Revenue (Line 8 / Line 9)			21.93%			14.85%
12	Rate Of Return On Common Equity			11.95%			10.15%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 And D-1
Columns (D) Thru (F): Schedules RLM-2, RLM-5, RLM-6 And RLM-18

Southwest Gas Corporation
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GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	REFERENCE	(A)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:		
1	Revenue		1.0000
2	Less: Uncollectibles	Company Schedule C-2, Adjustment No. 5, Line 2, Column (b)	0.0022
3	Subtotal	Line 1 - Line 2	0.9978
4	Less: Combined Federal And State Tax Rate	Line 14	0.3944
5	Subtotal	Line 3 - Line 4	0.6034
6	**Revenue Conversion Factor**	Line 1 / Line 5	$\boxed{1.6573}$
	CALCULATION OF EFFECTIVE TAX RATE:		
7	Arizona Taxable Income		1.0000
8	Arizona State Income Tax Rate		0.0697
9	Federal Taxable Income	Line 7 - Line 8	0.9303
10	Applicable Federal Income Tax Rate		0.3500
11	Effective Federal Income Tax Rate	Line 9 X Line 10	0.3256
12	Subtotal	Line 8 + Line 11	0.3953
13	Revenue Less Uncollectibles	Line 3	0.9978
14	Combined Federal And State Income Tax Rate	Line 12 X Line 13	0.3944

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RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO OCRB ADJUSTMENTS	REF.	(C) RUCO ADJUSTED AS OCRB
1	Gas Plant In Service	$1,685,504,145	$ (4,428,513)	(1)	$ 1,681,075,632
	Less:				
2	Accumulated Depreciation And Amortization	593,542,006	(1,089,621)	(1)	592,452,385
3	Net Gas Plant In Service (Line 1 - Line 2)	$1,091,962,139	$ (3,338,892)		$ 1,088,623,247
	Additions:				
4	Allowance For Working Capital (MDC-3, Page 1)	$ 881,148	$ (3,649,600)	(2)	$ (2,768,452)
5	Total Additions (Line 4)	$ 881,148	$ (3,649,600)		$ (2,768,452)
	Deductions:				
6	Customer Advances In Aid Of Construction	$ (7,027,372)	$ -		$ (7,027,372)
7	Customer Deposits	(23,912,141)	-		(23,912,141)
8	Deferred Income Taxes	(136,691,328)	223,252	(3)	(136,468,076)
9	Total Deductions (Sum Of Lines 6, 7 & 8)	$ (167,630,841)	$ 223,252		$ (167,407,589)
10	TOTAL ORIGINAL COST RATE BASE (Sum Of Lines 3, 5 & 9)	$ 925,212,447	$ (6,765,240)		$ 918,447,207

References:
- Column (A): Company Schedule B-1
- Column (B):
  - (1) Schedule RLM-3
  - (2) Schedule MDC-3
  - (3) Schedule MDC-1
- Column (C): Column (A) + Column (B)

Southwest Gas Corporation
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"DIRECT" TEST YEAR PLANT SCHEDULES
YEAR ENDED AUGUST 31, 2004

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
			COMPANY TEST YEAR AS FILED			ADJ. NO. 1	ADJ. NO. 2		RUCO ADJUSTMENT NO. 3			RUCO ADJUSTMENT NO. 4			RUCO AS ADJUSTED		
LINE NO.	ACCT NO.	ACCOUNT NAME	DEP RATE	TOTAL PLANT VALUE	ACCUMULATED DEPRECIATION	RUCO DR 7.01(C) ACC. DEP	PIPE SUR'Y/REP'R	PIPE SUR/REP ACC. DEP	CCNC NET ADDITIONS	ACC DEP CCNC ADDITIONS	ACC DEP CCNC RETIREMENTS	MISC INT'GIBLE NET PLANT	ACC. DEP. INT'G ADDITIONS	ACC. DEP INT'G RETIREMENTS	TOTAL PLANT VALUE	ACCUMULATED DEPRECIATION	NET PLANT VALUE
		Intangible Plant:															
1	301.0	Organization	Amor'd	$ 42,653	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,653	$ -	$ 42,653
2	302.0	Franchises & Consents	Amor'd	1,714,402	529,246	-	-	-	-	-	-	-	-	-	1,714,402	529,246	1,185,156
3	303.0	Miscellaneous Intangible	Amor'd	1,945,631	1,667,452	-	-	-	-	-	-	-	-	-	1,945,631	1,667,452	278,179
4		Total Intangible Plant		$ 3,702,686	$ 2,196,698	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,702,686	$ 2,196,698	$ 1,505,988
		Distribution Plant:															
5	374.1	Land & Land Rights	N/A	$ 351,685	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 351,685	$ -	$ 351,685
6	374.2	Rights Of Way	2.15%	720,979	274,994	-	-	-	-	-	-	-	-	-	720,979	274,994	445,985
7	375.0	Structures	1.15%	110,557	62,874	3,923	-	-	-	-	-	-	-	-	110,557	66,797	43,760
8	376.0	Mains	3.82%	789,647,065	273,373,290	-	(1,224,119)	(72,387)	(1,485,395)	6,390	40,038	-	-	-	786,937,551	273,267,255	513,670,296
9	378.0	Measuring & Regulating Station	4.12%	24,454,990	1,274,807	-	-	-	-	-	-	-	-	-	24,454,990	1,274,807	23,180,183
10	380.0	Services	5.30%	523,802,714	218,592,143	-	(1,115,660)	(61,455)	-	-	-	-	-	-	522,687,054	218,530,688	304,156,366
11	381.0	Meters	1.98%	156,809,964	30,981,761	-	-	-	-	-	-	-	-	-	156,809,964	30,981,761	125,828,203
12	385.0	Industrial Measuring & Reg. Station	4.31%	6,528,499	2,586,375	-	-	-	-	-	-	-	-	-	6,528,499	2,586,375	3,942,124
13	387.0	Other Equipment	5.26%	462,730	502,185	14,288	-	-	-	-	-	-	-	-	462,730	516,473	(53,743)
14		Total Distribution Plant		$1,502,889,183	$ 527,648,429	$ 18,211	$ (2,339,779)	$ (133,842)	$ (1,485,395)	$ 6,390	$ 40,038	$ -	$ -	$ -	$ 1,499,064,009	$ 527,499,150	$ 971,564,859
		General Plant:															
15	389.0	Land & Land Rights	N/A	$ 6,454,589	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,454,589	$ -	$ 6,454,589
16	390.1	Structures	1.84%	26,285,123	7,274,350	-	-	-	-	-	-	-	-	-	26,285,123	7,274,350	19,010,773
17	390.2	Structures - Leasehold Improv'ts	Amor'd	1,005,567	599,757	37,893	-	-	-	-	-	-	-	-	1,005,567	637,650	367,917
18	391.0	Office Furniture And Equipment	2.73%	4,849,827	656,607	-	-	-	-	-	-	-	-	-	4,849,827	656,607	4,193,220
19	391.1	Computer Equipment	14.87%	8,489,038	1,178,796	-	-	-	-	-	-	-	-	-	8,489,038	1,178,796	7,310,242
20	392.1	Transportation Equipment	7.65%	30,447,147	5,293,542	-	-	-	-	-	-	-	-	-	30,447,147	5,293,542	25,153,605
21	393.0	Stores Equipment	2.08%	481,909	14,058	-	-	-	-	-	-	-	-	-	481,909	14,058	467,851
22	394.0	Tools, Shop And Garage Equip	2.17%	4,891,998	(2,642,962)	-	-	-	-	-	-	-	-	-	4,891,998	(2,642,962)	7,534,960
23	395.0	Laboratory Equipment	3.93%	425,322	(150,109)	-	-	-	-	-	-	-	-	-	425,322	(150,109)	575,431
24	396.0	Power Operated Equipment	3.88%	3,807,547	1,118,830	-	-	-	-	-	-	-	-	-	3,807,547	1,118,830	2,688,717
25	397.0	Communication Equipment	8.88%	2,223,684	2,332,366	-	-	-	-	-	-	-	-	-	2,223,684	2,332,366	(108,682)
26	397.2	Telemetering Equipment	6.19%	560,307	432,184	-	-	-	-	-	-	-	-	-	560,307	432,184	128,123
27	398.0	Miscellaneous Equipment	4.53%	844,186	32,818	78	-	-	-	-	-	-	-	-	844,186	32,896	811,290
28		Total General Plant		$ 90,766,244	$ 16,140,237	$ 37,971	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,766,244	$ 16,178,208	$ 74,588,036
29		TOTAL DIRECT PLANT		$1,597,358,113	$ 545,985,364	$ 56,182	$ (2,339,779)	$ (133,842)	$ (1,485,395)	$ 6,390	$ 40,038	$ -	$ -	$ -	$ 1,593,532,939	$ 545,874,056	$1,047,658,883
30		Allocated Plant (See RLM-3, Page 2, Line 31)		88,146,035	47,556,640	-	-		(116,232)	(12,297)	-	(487,110)	(81,104)	884,911	87,542,693	46,578,329	40,964,364
31		TOTAL PLANT		$1,685,504,148	$ 593,542,004	$ 56,182	$ (2,339,779)	$ (133,842)	$ (1,601,627)	$ (5,907)	$ 40,038	$ (487,110)	$ (81,104)	$ 884,911	$ 1,681,075,632	$ 592,452,385	$1,088,623,247
32		Direct Plant As Per Company		$1,597,358,113	$ 545,985,364	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,597,358,113	$ 545,985,364	1,051,372,749
		Common Plant As Per Company		88,146,035	47,556,640	-	-	-	-	-	-	-	-	-	88,146,035	$ 47,556,640	40,589,394
33		Difference		$ -	$ -	$ 56,182	$ (2,339,779)	$ (133,842)	$ (1,601,627)	$ (5,907)	$ 40,038	$ (487,110)	$ (81,104)	$ 884,911	$ (4,428,516)	$ (1,089,619)	$ (3,338,896)

References:
Columns (A) (B) (C): Company Workpapers B-2, Sheets 1 Through 8 And C-2, Adjustment 17, Sheets 1 Through 5
Column (D): Company Response To RUCO Data Request 7.01(C)
Columns (E) (F): See Testimony, MDC
Columns (G) (H) (I): See Schedule RLM-4, Pages 1 & 2
Columns (J) (K) (L): See Testimony, MDC
Column (M): Sum Of Cols. (B) (E) (G) (J)
Column (N): Sum Of Cols. (C) (D) (F) (H) (K) - Minus Cols. (I) (L)
Column (O): Column (M) - Column (N)

Southwest Gas Corporation
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

"SYSTEM ALLOCABLE" TEST YEAR PLANT SCHEDULES
YEAR ENDED AUGUST 31, 2004

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
				COMPANY TEST YEAR AS FILED		ADJ. NO. 1	ADJ. NO. 2		RUCO ADJUSTMENT NO. 3			RUCO ADJUSTMENT NO. 4			RUCO AS ADJUSTED		
LINE NO.	ACCT NO.	ACCOUNT NAME	DEP RATE	TOTAL PLANT VALUE	ACCUMULATED DEPRECIATION	RUCO DR 7.01(C) ACC. DEP	PIPE SURV/REP'R	PIPE SUR/REP ACC. DEP	CCNC NET ADDITIONS	ACC DEP CCNC ADDITIONS	ACC DEP CCNC RETIREMENTS	MISC INT'GIBLE NET PLANT	ACC. DEP. INT'G ADDITIONS	ACC. DEP. INT'G RETIREMENTS	TOTAL PLANT VALUE	ACCUMULATED DEPRECIATION	NET PLANT VALUE
		Intangible Plant:															
1	301.0	Organization	0.00%	$ 61,816	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,816	$ -	$ 61,816
2	302.0	Franchises & Consents	Amor'd	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	303.0	*Miscellaneous Intangible*	*Amor'd*	*105,174,215*	*60,385,073*	-	-	-	-	-	-	(845,975)	(140,855)	1,536,844	105,328,240	58,707,374	46,620,866
4		Total Intangible Plant		$ 106,235,031	$ 60,385,073	$ -	$ -	$ -	$ -	$ -	$ -	$ (845,975)	$ (140,855)	$ 1,536,844	$ 105,390,056	$ 58,707,374	$ 46,682,682
		Distribution Plant:															
5	374.1	Land & Land Rights	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	374.2	Rights Of Way	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	375.0	Structures	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	376.0	Mains	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	378.0	Measuring & Regulating Station	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	380.0	Services	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	381.0	Meters	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	385.0	Industrial Measuring & Reg. Station	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	387.0	Other Equipment	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14		Total Distribution Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		General Plant:															
15	389.0	Land & Land Rights	0.00%	$ 391,307	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 391,307	$ -	$ 391,307
16	390.1	Structures	2.46%	11,831,108	3,565,211	-	-	-	-	-	-	-	-	-	11,831,108	3,565,211	8,265,897
17	390.2	*Structures - Leasehold Improv'ts*	*Amor'd*	*3,144,329*	*2,895,028*	-	-	-	-	-	-	-	-	-	3,144,329	2,895,028	249,301
18	391.0	Office Furniture And Equipment	3.99%	7,755,795	1,861,177	-	-	-	(4,145)	(83)	-	-	-	-	7,751,650	1,861,094	5,890,556
19	391.1	Computer Equipment	30.01%	13,573,926	10,549,263	-	-	-	(128,028)	(19,211)	-	-	-	-	13,445,898	10,530,052	2,915,846
20	392.1	Trans. Equip. - Light Vehicles	6.42%	3,389,404	1,095,677	-	-	-	(50,507)	(1,621)	-	-	-	-	3,338,897	1,094,056	2,244,841
21	393.0	Trans. Equip. - Heavy Vehicles	6.42%	111,293	(34,504)	-	-	-	-	-	-	-	-	-	111,293	(34,504)	145,797
22	394.0	Stores Equipment	4.45%	24,106	(5,005)	-	-	-	(16,720)	(372)	-	-	-	-	7,386	(5,377)	12,763
23	395.0	Tools, Shop And Garage Equip.	4.10%	414,693	(29,696)	-	-	-	-	-	-	-	-	-	414,693	(29,696)	444,389
24	396.0	Laboratory Equipment	3.05%	268,894	82,474	-	-	-	-	-	-	-	-	-	268,894	82,474	186,420
25	397.0	Communication Equipment	9.88%	4,605,689	2,519,905	-	-	-	-	-	-	-	-	-	4,605,689	2,519,905	2,085,784
26	397.2	Telemetering Equipment	20.38%	401,430	(186,565)	-	-	-	-	-	-	-	-	-	401,430	(186,565)	587,995
27	398.0	Miscellaneous Equipment	5.65%	937,148	(105,377)	-	-	-	(2,462)	(70)	-	-	-	-	934,686	(105,447)	1,040,133
28		Total General Plant		$ 46,849,122	$ 22,207,588	$ -	$ -	$ -	$ (201,862)	$ (21,356)	$ -	$ -	$ -	$ -	$ 46,647,260	$ 22,186,232	$ 24,461,028
29		TOTAL ALLOCABLE PLANT		$ 153,085,153	$ 82,592,661	$ -	$ -	$ -	$ (201,862)	$ (21,356)	$ -	$ (845,975)	$ (140,855)	$ 1,536,844	$ 152,037,316	$ 80,893,606	$ 71,143,710
30		Allocation Factor		57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%
31		TOTAL ALLOCATE PLANT		$ 88,146,035	$ 47,556,640	$ -	$ -	$ -	$ (116,232)	$ (12,297)	$ -	$ (487,110)	$ (81,104)	$ 884,911	$ 87,542,693	$ 46,578,323	$ 40,964,364

References:
Columns (A) (B) (C): Company Workpapers B-2, Sheets 1 Through 8 And C-2, Adjustment 17, Sheets 1 Through 5
Column (D): Company Response To RUCO Data Request 7.01(C)
Columns (E) (F): See Testimony, MDC
Columns (G) (H) (I): See Schedule RLM-4, Pages 1 & 2
Columns (J) (K) (L): See Testimony, MDC
Column (M): Sum Of Cols. (B) (E) (G) (J)
Column (N): Sum Of Cols. (C) (D) (F) (H) (K) - Minus Cols. (I) (L)
Column (O): Column (M) - Column (N)

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Schedule RLM-4
Page 1 of 2

EXPLANATION OF SWG TEST-YEAR PLANT ADJUSTMENT NO. 20
ARIZONA DIRECT - COMPLETED CONSTRUCTION NOT CLASSIFIED

LINE NO.	ACCT. NO.	DESCRIPTION	(A) CONST. WK ORDER	(B) RETIRE'T WK ORDER	(C) IN-SER. DATE	(D) ACTUAL CONST. COST	(E) ACTUAL RETIRE'T COST
		DISTRIBUTION PLANT					
	376.0	Mains					
1		Replace 1960' of 1 1/2" Steel	C3662360	R3662360	Jul-04	$ 50,393	$ (3,309)
2		Replace 276' of 2"PVC	C3681448	R3681448	Jan-04	16,540	(209)
3		Replace Approximately 1800'	C4262016	R4262016	Aug-04	103,420	-
4		Replace 195' of 2" Drisco	C2585555	R2585555	Jul-04	5,974	(1,941)
5		Relocate Exisitng 4" Steel	C4264224	R4264224	Aug-04	2,646	(16,369)
6		Replace 2" Srisco Main	C4269542	R4269542	Jul-04	525	(2,295)
7		Replace 538' of 2"PE800	C4274671	R4274671	Aug-04	(572)	(5,222)
8		Instal 138' of 4" PE Main	C3660167	R3660167	May-04	26,546	(1,492)
9		Abandon 2995'	C3693590	R3693590	Aug-04	68,349	(9,201)
10		Inbstall 307' of 2" Steel Main	C3213815	R3213815	Aug-04	21,553	-
11		Install 624' of 4" PE Main	C4236882		Aug-04	49,998	-
12		Install 844' of 2" PE Main	C4239280		Aug-04	29,220	-
13		SUBTOTAL DISTRIBUTION PLANT				$ 374,592	$ (40,038)
14		RUCO RECOMMENDED NET ARIZONA DIRECT CCNC					$ 334,554
15		Company As Filed					1,819,949
16		RUCO ADJUSTMENT TO ARIZONA DIRECT CCNC					$(1,485,395)

Reference
Columns (A) (B) (C) (D) (E): Company Response To RUCO Date Request No. 13

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EXPLANATION OF SWG TEST-YEAR PLANT ADJUSTMENT NO. 20 - CONT'D
SYSTEM ALLOCABLE - COMPLETED CONSTRUCTION NOT CLASSIFIED

LINE NO.	ACCT. NO.	DESCRIPTION	(A) CONST. WK ORDER	(B) RETIRE'T WK ORDER	(C) IN-SER. DATE	(D) ACTUAL CONST. COST	(E) RUCO ADJUSTM'T
		GENERAL PLANT					
	391.0	Office Furniture & Equipment					
1		Purchase a Shrink Wrap Machine	C4100077		Aug-04	$ 8,162	
2		Purchase a Stretch Wrap Machine	C4100026		Jan-05	Outside TY	
3		Subtotal Office Furniture & Furniture				$ 8,162	
5		RUCO Recommended Net Arizona System Allocated CCNC				$ 8,162	
6		Company As Filed				12,307	
7		RUCO ADJUSTMENT TO SYSTEM ALLOCABLE CCNC IN ACCOUNT 391.0					$ (4,145)
	391.1	Computer Equipment					
8		Purchase 60 Itron Terminals	C4100044		Not In Service	Outside TY	
9		Purchase IP530 Base System	C4100088		Nov-04	Outside TY	
10		Purchase Bowe Bell & Howell H. Total Controll	C4100073		Not In Service	Outside TY	
11		Subtotal Computer Equipment				$ -	
13		RUCO Recommended Net Arizona System Allocated CCNC				$ -	
14		Company As Filed				$ 128,028	
15		RUCO ADJUSTMENT TO SYSTEM ALLOCABLE CCNC IN ACCOUNT 391.1					$(128,028)
	392.1	Transportation Equipment					
16		Purchase 1 Cheverolet Trailbazer	C4100089		Nov-04	Outside TY	
17		Purchase 2005 Explorer/4546	C4100097		Nov-04	Outside TY	
18		Subtotal Transportation Equipment				$ -	
20		RUCO Recommended Net Arizona System Allocated CCNC				$ -	
21		Company As Filed				$ 50,507	
22		RUCO ADJUSTMENT TO SYSTEM ALLOCABLE CCNC IN ACCOUNT 392.1					$ (50,507)
	394.0	Tools, Shop, & Garage Equipment					
23		Purchase Chlor-rid Soil Testers	C4100083		Sep-04	Outside TY	
24		Purchase Wirescope Testers	C4100082		Jan-05	Outside TY	
25		Subtotal Tools, Shop, & Grarage Equipment				$ -	
27		RUCO Recommended Net Arizona System Allocated CCNC				$ -	
28		Company As Filed				$ 16,720	
29		RUCO ADJUSTMENT TO SYSTEM ALLOCABLE CCNC IN ACCOUNT 394.0					$ (16,720)
	398.0	Miscellaneous Equipment					
30		Purchase OSS Projector	C4100096		Oct-04	Outside TY	
31		Subtotal Miscellaneous Equipment				$ -	
32		RUCO Recommended Net Arizona System Allocated CCNC				$ -	
33		Company As Filed				$ 2,462	
34		RUCO ADJUSTMENT TO SYSTEM ALLOCABLE CCNC IN ACCOUNT 398.0					$ (2,462)

Reference
Columns (A) (B) (C) (D) (E): Company Response To RUCO Date Request No. 13

Southwest Gas Corporation
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RATE BASE - RECONSTRUCTED COST NEW DEPRECIATED

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS RCND	(B) RUCO RCND ADJUSTMENTS	(C) RUCO ADJUSTED AS RCND
1	Gas Plant In Service	$ 2,441,205,028	$ (6,414,050)	$ 2,434,790,978
	Less:			
2	Accumulated Depreciation And Amortization	856,813,179	(1,572,933)	855,240,246
3	Net Gas Plant In Service (Line 1 - Line 2)	$ 1,584,391,849	$ (4,841,117)	$ 1,579,550,732
	Additions:			
4	Allowance For Working Capital	$ 881,148	$ (3,649,600)	$ (2,768,452)
5	Total Additions (Line 4)	$ 881,148	$ (3,649,600)	$ (2,768,452)
	Deductions:			
6	Customer Advances In Aid Of Construction	$ (7,027,372)	$ -	$ (7,027,372)
7	Customer Deposits	(23,912,141)	-	(23,912,141)
8	Deferred Income Taxes	(136,691,328)	223,252	(136,468,076)
9	Total Deductions (Sum Lines 6, 7 & 8)	$ (167,630,841)	$ 223,252	$ (167,407,589)
10	TOTAL RCND RATE BASE	$ 1,417,642,156	$ (8,267,465)	$ 1,409,374,691

References:
Column (A): Company Schedule B-1
Column (B): Column (C) - Column (A)
Column (C): OCRB (RLM-2, Column (C)) X Same Ratio As The Company's RCND Is To Its OCRB (144.84%)

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OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJ'TMENTS	(C) RUCO TEST YEAR AS ADJUSTED	(D) RUCO PROPOSED CHANGES	(E) RUCO AS RECOMMENDED
1	Revenues	$ 322,865,978	$ -	$ 322,865,978	$ 47,952,611	$ 370,818,589
2	Gas Cost	-	-	-	-	-
3	TOTAL MARGIN	$ 322,865,978	$ -	$ 322,865,978	$ 47,952,611	$ 370,818,589
	EXPENSES:					
4	Other Gas Supply	$ 740,391	$ (21,030)	$ 719,361	$ -	$ 719,361
5	Distribution	78,580,466	(4,781,849)	73,798,617	-	73,798,617
6	Customer Accounts	34,003,279	(1,500,922)	32,502,357	-	32,502,357
7	Customer Information	548,496	(16,820)	531,676	-	531,676
8	Sales	-	-	-	-	-
	Administration & General					
9	Direct	6,993,300	(83,723)	6,909,577	-	6,909,577
10	System Allocable	45,487,895	(3,977,019)	41,510,876	-	41,510,876
	Depreciation & Amortization					
11	Direct	67,338,861	(109,637)	67,229,224	-	67,229,224
12	System Allocable	7,062,583	(123,789)	6,938,794	-	6,938,794
13	Regulatory Amortizations	1,548,204	(1,044,968)	503,236	-	503,236
14	Other Taxes	33,455,124	(1,267,863)	32,187,261	-	32,187,261
15	Interest On Cust. Deposits	717,364	-	717,364	-	717,364
16	Income Taxes	2,156,664	6,715,836	8,872,500	19,019,109	27,891,609
17	TOTAL EXPENSES	$ 278,632,626	$ (6,211,784)	$ 272,420,843	$ 19,019,109	$ 291,439,952
18	NET INCOME (LOSS)	$ 44,233,351		$ 50,445,135		$ 79,378,637

References:
Column (A): Company Schedule C-1
Column (B): Testimony, RLM And Schedule RLM-7
Column (C): Column (A) + Column (B)
Column (D): Testimony, RLM And Schedule RLM-1, Pages 1 & 2
Column (E): Column (C) + Column (D)

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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) LEFT BLANK	(C) ADJ #3	(D) LEFT BLANK	(E) ADJ #7	(F) ADJ #8	(G) ADJ #10	(H) ADJ #12	(I) ADJ #14
1	Revenues	$322,865,978	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Gas Cost	-	-	-	-	-	-	-	-	-
3	TOTAL MARGIN	$322,865,978	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	EXPENSES:									
4	Other Gas Supply	$ 740,391	$ -	$ (11,215)	$ -	$ -	$ -	$ -	$ -	$ -
5	Distribution	78,580,466	-	(2,369,584)	-	-	-	-	(1,488,287)	(188,165)
6	Customer Accounts	34,003,279	-	(1,109,837)	-	-	-	-	-	(10,715)
7	Customer Information	548,496	-	(12,880)	-	-	-	-	-	-
8	Sales	-	-	-	-	-	-	-	-	-
	Administration & General									
9	Direct	6,993,300	-	(31,720)	-	-	-	-		-
10	System Allocable	45,487,895	-	(700,309)	-	(75,385)	240,016	(346,404)	-	(147,419)
	Depreciation & Amortization									
11	Direct	67,338,861	-	-	-	-	-	-	-	-
12	System Allocable	7,062,583	-	-	-	-	(12,932)	-	-	-
13	Regulatory Amortizations	1,548,204	-	-	-	-	-	-	(1,044,968)	-
14	Other Taxes	33,455,124	-	-	-	-	-	-	-	-
15	Interest On Cust. Deposits	717,364	-	-	-	-	-	-	-	-
16	Income Taxes	2,156,664	-	-	-	-	-	-	-	-
17	TOTAL EXPENSES	$278,632,627	$ -	$ (4,235,547)	$ -	$ (75,385)	$ 227,084	$ (346,404)	$ (2,533,255)	$ (346,299)
18	NET INCOME (LOSS)	$ 44,233,351								

Adjustment No.:	References:
1 - Left Blank	
3 - Labor And Labor Loading Annualization	Testimony, RLM And Schedule RLM-8, Pages 1 To 7
4 - Left Blank	
7 - Amercian Gas Association ("AGA") Dues	Testimony, RLM And Schedule RLM-9, Page 1
8 - Sarbanas-Oxley Section 404 Compliance	Testimony, MDC And Schedule MDC-4
10 - Injuries And Damages	Testimony, RLM And Schedule RLM-10, Page 1
12 - *Transmission Integrity Management Program*	*Testimony, MDC And Schedule MDC-5*
14 - Miscellaneous Adjustments	Testimony, RLM And Schedule RLM-11, Page 1

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SUMMARY OF OPERATING INCOME ADJUSTMENTS - CONT'D
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(J) ADJ #17	(K) ADJ #18	(L) ADJ #20	(M) ADJ #21	(N) LEFT BLANK	(O) LEFT BLANK	(P) LEFT BLANK	(Q) INCOME TAX	(R) RUCO AS AD'TED
1	Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$322,865,978
2	Gas Cost	-	-	-	-	-	-	-	-	-
3	TOTAL MARGIN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$322,865,978
	EXPENSES:									
4	Other Gas Supply	$ -	$ -	$ -	$ (9,815)	$ -	$ -	$ -	$ -	$ 719,361
5	Distribution	-	-	-	(735,813)	-	-	-	-	73,798,617
6	Customer Accounts	-	-	-	(380,369)	-	-	-	-	32,502,357
7	Customer Information	-	-	-	(3,939)	-	-	-	-	531,676
8	Sales	-	-	-	-	-	-	-	-	-
	Administration & General									
9	Direct	-	-	-	(52,003)	-	-	-	-	6,909,577
10	System Allocable	-	-	(2,563,384)	(384,133)	-	-	-	-	41,510,876
	Depreciation & Amortization									
11	Direct	(109,637)	-	-	-	-	-	-	-	67,229,224
12	System Allocable	(110,857)	-	-	-	-	-	-	-	6,938,794
13	Regulatory Amortizations	-	-	-	-	-	-	-	-	503,236
14	Other Taxes	-	(1,267,863)	-	-	-	-	-	-	32,187,261
15	Interest On Cust. Deposits	-	-	-	-	-	-	-	-	717,364
16	Income Taxes	-	-	-	-	-	-	-	6,715,836	8,872,500
17	TOTAL EXPENSES	$ (220,495)	$ (1,267,863)	$ (2,563,384)	$ (1,566,073)	$ -	$ -	$ -	$ 6,715,836	$272,420,843
18	NET INCOME (LOSS)									$ 50,445,135

Adjustment No.:
17 - Deprecitation/Amortization Expense
18 - Property Tax Expense
20 - RUCO Adjustment To Management Incentive Plan
21 - RUCO Adjustment To SERP
22 - Left Blank
23 - Left Blank
24 - Left Blank
25 - RUCO Adjustment To Income Tax

References:
Testimony, RLM, Schedule RLM-12, Pages 1 & 2 and Schedule MDC-6
Testimony, RLM And Schedule RLM-13, Page 1
Testimony, MDC
Testimony, RLM And Schedule RLM-14, Page 1

Testimony, RLM And Schedule RLM-15, Page 1

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3
LABOR AND LABOR LOADING ADJUSTMENT

LINE NO.	ARIZONA ACOUNT NUMBERS	(A) RUCO AS ADJUSTED LABOR (See RLM-8, Page 2, Col. (I)	(B) LOADING (See RLM-8, Page 2, Col. (J)	(C) TOTAL (Sum Of Columns (A) And (B)
	OPERATIONS			
1	813	$ 455,832	$ 216,139	$ 671,971
2	851	-	-	-
3	870	4,517,245	2,470,143	6,987,388
4	871	353,390	168,755	522,145
5	874	3,218,183	1,765,741	4,983,924
6	875	1,209,635	662,867	1,872,502
7	878	3,567,456	1,958,862	5,526,318
8	879	4,214,601	2,316,642	6,531,243
9	880	3,878,484	2,122,265	6,000,748
10	901	2,198,811	1,209,060	3,407,871
11	902	3,158,586	1,732,697	4,891,282
12	903	11,035,752	5,836,032	16,871,784
13	905	229,622	125,856	355,478
14	908	169,558	93,031	262,589
15	909	-	-	-
16	910	483	254	737
17	920	29,532,138	14,034,893	43,567,031
18	922	-	-	-
19	930	29,401	13,956	43,357
20	SUBTOTAL	$ 67,769,176	$ 34,727,192	$ 102,496,368
	MAINTENANCE			
21	885	$ 1,466,021	$ 802,355	$ 2,268,376
22	886	8,442	4,598	13,040
23	887	4,620,011	2,533,733	7,153,744
24	889	688,420	377,577	1,065,997
25	892	3,272,834	1,796,791	5,069,625
26	893	694,134	379,992	1,074,126
27	894	92,652	50,652	143,303
28	CORPORATE DIRECT 935	418,785	229,510	648,295
	SYSTEM ALLOCABLE 935	181,977	86,925	268,902
29	SUBTOTAL	$ 11,261,299	$ 6,175,207	$ 17,705,408
30	TOTALS	$ 79,030,475	$ 40,902,400	$ 120,201,776

LINE NO.	FUNCTIONALIZATION	COMPANY AS FILED (WP, ADJ. 3, Pg 11 Thru 24)	RUCO AS ADJUSTED (From Col. (C), Lines 1 To 29)	ADJUSTMENT (Col. (B) - (A)) (See RLM-7, Page 1, Col. (C))
31	OTHER GAS SUPPLY (813)	$ 683,186	$ 671,971	$ (11,215)
32	DISTRIBUTION (870-880 & 885-894)	51,582,063	49,212,479	(2,369,584)
33	CUST. ACC'TS (901, 902, 903 & 905)	26,636,254	25,526,417	(1,109,837)
34	CUST. SER. & INFO (908, 909, & 910)	276,206	263,326	(12,880)
35	SALES			
	ADMINISTRATION & GENERAL			
36	CORPORATE DIRECT (935)	680,015	648,295	(31,720)
37	SYS. ALLOC. (920, 922, 930 & 935)	44,579,599	43,879,290	(700,309)
38	TOTAL	$ 124,437,323	$ 120,201,776	$ (4,235,547)
39	RUCO ADJUSTMENT TO LABOR AND LABOR LOADING (See RLM-7, Page 1, Col (C), Line17)			$ (4,235,547)

References:
Columns (A) (B) (C): Calculated From The Following 6 Pages Of Schedule RLM-8

Southwest Gas Corporation
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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANNUALIZED LABOR AND LOADING PER RUCO ADJUSTMENTS

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
LINE	ACCT	ARIZONA		CORPORATE DIRECT		TOTAL DIRECT		SYSTEM ALLOCATED		TOTAL ANNUALIZATION	
		LABOR	LOADING	LABOR	LOADING	LABOR	LOADING	LABOR	LOADING	LABOR	LOADING
NO.	NO.	RLM-8, P5, (C)	RLM-8, P6, (C)	RLM-8, P5, (F)	RLM-8, P6, (F)	Col. (A) + (C)	Col. (B) + (D)	RLM-8, P5, (I)	RLM-8, P6, (I)	Col. (E) + (G)	Col. (F) + (H)
	OPERATIONS										
1	813	$ -	$ -	$ 455,832	$ 216,139	$ 455,832	$ 216,139	$ -	$ -	$ 455,832	$ 216,139
2	851	-	-	-	-	-	-	-	-	-	-
3	870	4,217,298	2,310,497	299,947	159,646	4,517,245	2,470,143	-	-	4,517,245	2,470,143
4	871	11,559	6,270	341,832	162,484	353,390	168,755	-	-	353,390	168,755
5	874	3,218,183	1,765,741	-	-	3,218,183	1,765,741	-	-	3,218,183	1,765,741
6	875	1,209,635	662,867	-	-	1,209,635	662,867	-	-	1,209,635	662,867
7	878	3,567,456	1,958,862	-	-	3,567,456	1,958,862	-	-	3,567,456	1,958,862
8	879	4,214,601	2,316,642	-	-	4,214,601	2,316,642	-	-	4,214,601	2,316,642
9	880	3,850,637	2,109,507	27,847	12,758	3,878,484	2,122,265	-	-	3,878,484	2,122,265
10	901	2,198,811	1,209,060	-	-	2,198,811	1,209,060	-	-	2,198,811	1,209,060
11	902	3,158,586	1,732,697	-	-	3,158,586	1,732,697	-	-	3,158,586	1,732,697
12	903	8,148,433	4,466,708	1,335,013	631,290	9,483,445	5,097,998	1,552,307	738,034	11,035,752	5,836,032
13	905	229,622	125,856	-	-	229,622	125,856	-	-	229,622	125,856
14	908	169,558	93,031	-	-	169,558	93,031	-	-	169,558	93,031
15	909	-	-	-	-	-	-	-	-	-	-
16	910	483	254	-	-	483	254	-	-	483	254
17	920	-	-	-	-	-	-	29,532,138	14,034,893	29,532,138	14,034,893
18	922	-	-	-	-	-	-	-	-	-	-
19	930	-	-	-	-	-	-	29,401	13,956	29,401	13,956
20	SUBTOT	$ 34,194,861	$ 18,757,991	$ 2,460,470	$ 1,182,317	$ 36,655,331	$ 19,940,309	$ 31,113,845	$ 14,786,884	$ 67,769,176	$ 34,727,192
	MAINTENANCE										
21	885	$ 1,364,675	$ 748,644	$ 101,347	$ 53,711	$ 1,466,021	$ 802,355	$ -	$ -	$ 1,466,021	$ 802,355
22	886	8,442	4,598	-	-	8,442	4,598	-	-	8,442	4,598
23	887	4,620,011	2,533,733	-	-	4,620,011	2,533,733	-	-	4,620,011	2,533,733
24	889	688,420	377,577	-	-	688,420	377,577	-	-	688,420	377,577
25	892	3,272,834	1,796,791	-	-	3,272,834	1,796,791	-	-	3,272,834	1,796,791
26	893	694,134	379,992	-	-	694,134	379,992	-	-	694,134	379,992
27	894	92,652	50,652	-	-	92,652	50,652	-	-	92,652	50,652
28	935	418,785	229,510	-	-	418,785	229,510	181,977	86,925	600,762	316,435
29	SUBTOT	$ 11,159,952	$ 6,121,496	$ 101,347	$ 53,711	$ 11,261,299	$ 6,175,207	$ 181,977	$ 86,925	$ 11,443,275	$ 6,262,132
30	O & M	$ 45,354,813	$ 24,879,488	$ 2,561,817	$ 1,236,028	$ 47,916,630	$ 26,115,516	$ 31,295,822	$ 14,873,809	$ 79,212,451	$ 40,989,325

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANNUALIZED LABOR

LINE NO.	DESCRIPTION	(A) ARIZONA DIRECT	(B) CORPORATE DIRECT	(C) SYSTEM ALLOCABLE	(D) TOTAL
1	ANNUALIZED SALARY (WP C-2, ADJ. 3, SH 3)	$ 61,779,296	$ 2,843,265	$ 36,475,304	
	LESS:				
2	SALES/MARK'G DISALLOWANCE (RLM-8, Pg 7)	(2,125,266)	-	(767,168)	
3	SUBTOTAL (Line 1 + Line 2)	$ 59,654,030	$ 2,843,265	$ 35,708,136	
	PLUS:				
4	2005 WAGES INCREASE % (See Testimony, RLM)	0.00%	0.00%	0.00%	
5	2005 WAGE INCREASE (Line 3 X Line 4)	$ -	$ -	$ -	
6	SUBTOTAL (Line 3 + Line 5)	$ 59,654,030	$ 2,843,265	$ 35,708,136	
7	OVERTIME % (WP C-2, ADJ. 3, SH 4)	8.53%	2.77%	0.43%	
8	OVERTIME (Line 6 X Line 7)	$ 5,090,722	$ 78,790	$ 154,180	
9	TOTAL ANNUALIZED PAYROLL (Line 1 + Line 8)	$ 64,744,752	$ 2,922,055	$ 36,629,484	
	LESS:				
10	PERCENT INDIRECT TIME (WP C-2, ADJ. 3, SH 4)	13.53%	12.33%	12.33%	
11	INDIRECT TIME (Line 9 X Line 10)	$ 8,763,049	$ 360,238	$ 4,515,773	
12	NET ANNUALIZED LABOR (Line 9 + Line 11)	$ 55,981,703	$ 2,561,817	$ 32,113,712	
13	O & M RATIO (WP C-2, ADJ. 3, SH 2)	81.02%	100.00%	96.51%	
14	O & M SUBTOTAL (Line 12 X Line 13)	$ 45,354,815	$ 2,561,817	$ 30,993,739	
15	ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 15)	100.00%	100.00%	57.58%	
16	O & M SUBTOTAL ALLOCABLE (Line 14 X Line 15)	$ 45,354,815	$ 2,561,817	$ 17,846,195	
17	NET OF PAIUTE (SEE NOTE A)	$ -	$ -	$ (704,228)	
18	O & M TOTAL ALLOCABLE (Line 16 + Line 17)	$ 45,354,815	$ 2,561,817	$ 17,141,967	
19	COMPANY AS FILED (WP C-2, ADJ. 3, SH 15 & 20)	$ 48,546,243	$ 2,620,441	$ 17,552,008	
20	RUCO ADJUSTMENT (Line 18 - Line 19)	$ (3,191,429)	$ (58,624)	$ (410,041)	$ (3,660,095)
21	ANNUALIZED EMPLOYEES (WP C-2, ADJ. 3, SH 3)	1,171	39	502	1,712

NOTE (A)

22	PAIUTE ADJUSTMENT	
23	RUCO ADJUSTED 920	$ 29,532,138
24	RUCO ADJUSTED 930	29,401
25	RUCO ADJUSTED 935	181,977
26	SUBTOTAL (Sum Of Lines 23, 24 & 25)	$ 29,743,515
27	PAIUTE ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 19)	-4.29%
28	NET SYSTEM ALLOCATON - PAIUTE (Line 26 X Line 28)	$ (1,275,997)
29	O & M RATIO (WP C-2, ADJ. 3, SH 20)	95.85%
30	O & M SUBTOTAL (Line 28 X Line 29)	$ (1,223,043)
31	ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 20)	57.58%
32	SYSTEM ALLOCATION - PAIUTE (Line 30 X Line 31)	$ (704,228)

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANUALIZED FICA, MEDICARE, FUTA, AND SUTA

LINE NO.	DESCRIPTION	(A) ARIZONA DIRECT	(B) CORPORATE DIRECT	(C) SYSTEM ALLOCABLE	(D) TOTAL
	ANNUALIZED FICA				
1	RUCO ANNUALIZED LABOR (RLM-8, PG. 3, LINE 9)	$ 64,744,752	$ 2,922,055	$ 36,629,484	
2	SALARIES NOT SUBJECT TO FICA (RUCO DR 2.08)	693,076	233,025	2,989,398	
4	LABOR SUBJECT TO FICA (Line 1 - Line 2)	$ 64,051,676	$ 2,689,030	$ 33,640,086	
5	FICA RATE	6.20%	6.20%	6.20%	
6	TOTAL ANNUALIZED FICA (Line 4 X Line 5)	$ 3,971,204	$ 166,720	$ 2,085,685	
	ANNUALIZED MEDICARE				
7	ANNUALIZED LABOR (Line 1)	$ 64,744,752	$ 2,922,055	$ 36,629,484	
8	MEDICARE RATE	1.45%	1.45%	1.45%	
9	TOTAL ANNUALIZED MEDICARE (Line 7 X Line 8)	$ 938,799	$ 42,370	$ 531,128	
10	TOTAL FICA AND MEDICARE (Line 6 + Line 9)	$ 4,910,003	$ 209,090	$ 2,616,813	$ 7,735,905
	FUTA				
11	TAX BASE FACTOR	$ 7,000	$ 7,000	$ 7,000	
12	NUMBER OF EMPLOYEES (WP, ADJ. 3, SH 4)	1171	39	502	
13	TAX BASE (Line 11 X Line 12)	$ 8,197,000	$ 273,000	$ 3,514,000	
14	FUTA RATE	0.80%	0.80%	0.80%	
15	TOTAL FUTA (Line 13 X Line 14)	$ 65,576	$ 2,184	$ 28,112	$ 95,872
	SUTA				
16	TAX BASE FACTOR	$ 7,000	$ 22,000	$ 22,000	
17	NUMBER OF EMPLOYEES (WP, ADJ. 3, SH 4)	1171	39	502	
18	TAX BASE (Line 16 X Line 17)	$ 8,197,000	$ 858,000	$ 11,044,000	
19	SUTA RATE	0.06%	0.30%	0.30%	
20	TOTAL SUTA (Line 18 X Line 19)	$ 4,918	$ 2,574	$ 33,132	$ 40,624
	NET OF PAIUTE (SEE NOTE A)			$ (606,425)	
21	TOTAL LABOR LOADING (Sum Of Lines 11, 16 & 21)	$ 4,980,497	$ 213,848	$ 2,071,632	$ 7,872,402
22	COMPANY AS FILED (WP C-2, ADJ. 3, SH 5)	$ 5,329,017	$ 218,963	$ 2,742,440	$ 8,290,420
23	DIFFERENCE (Line 21 - Line 22)	$ (348,520)	$ (5,115)	$ (670,808)	$ (1,024,443)
	LESS:				
24	PERCENT INDIRECT TIME (WP C-2, ADJ. 3, SH 4)	13.53%	12.33%	12.33%	12.74%
25	INDIRECT TIME (Line 23 X Line 24)	$ (47,171)	$ (631)	$ (82,699)	$ (130,501)
26	NET ANNUALIZED LABOR LOADING (L 23 - L 25)	$ (301,349)	$ (4,485)	$ (588,109)	$ (893,942)
27	O & M RATIO (WP C-2, ADJ. 3, SH 2)	81.02%	100.00%	96.51%	91.31%
28	O & M SUBTOTAL (Line 26 X Line 27)	$ (244,144)	$ (4,485)	$ (567,599)	$ (816,228)
29	ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 15)	100.00%	100.00%	57.58%	70.50%
30	RUCO ADJUSTMENT (Line 28 X Line 29)	$ (244,144)	$ (4,485)	$ (326,823)	$ (575,452)
	NOTE (A)				
	PAIUTE ADJUSTMENT				
31	RUCO ADJUSTED 920		$ 14,034,893		
32	RUCO ADJUSTED 930		13,956		
33	RUCO ADJUSTED 935		86,925		
34	SUBTOTAL (Sum Of Lines 23, 24 & 25)		$ 14,135,775		
35	PAIUTE ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 19)		-4.29%		
36	NET SYSTEM ALLOCATON - PAIUTE (Line 34 X Line 35)		$ (606,425)		

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANUALIZED LABOR

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		ARIZONA DIRECT			CORPORATE DIRECT			SYSTEM ALLOCATED		
LINE NO.	ACOUNT CODE	COMPANY AS FILED	RUCO ADJUSTMENT	RUCO AS ADJUSTED	COMPANY AS FILED	RUCO ADJUSTMENT	RUCO AS ADJUSTED	COMPANY AS FILED	RUCO ADJUSTMENT	RUCO AS ADJUSTED
		Co. WP, Adj. 3	Pro Rated Pg 3	Col. (A) - (B)	Co. WP, Adj. 3	Pro Rated Pg 3	Col. (D) - (E)	Co. WP, Adj. 3	Pro Rated Pg 3	Col. (G) - (H)
	OPERATIONS									
1	813	$ -	$ -	$ -	$ 466,263	$ (10,431)	$ 455,832	$ -	$ -	$ -
2	851	-	-	-	-	-	-	-	-	-
3	870	4,514,052	(296,754)	4,217,298	306,811	(6,864)	299,947	-	-	-
4	871	12,372	(813)	11,559	349,654	(7,822)	341,832	-	-	-
5	874	3,444,633	(226,450)	3,218,183	-	-	-	-	-	-
6	875	1,294,752	(85,117)	1,209,635	-	-	-	-	-	-
7	878	3,818,483	(251,027)	3,567,456	-	-	-	-	-	-
8	879	4,511,165	(296,564)	4,214,601	-	-	-	-	-	-
9	880	4,121,590	(270,953)	3,850,637	28,484	(637)	27,847	-	-	-
10	901	2,353,532	(154,721)	2,198,811	-	-	-	-	-	-
11	902	3,380,842	(222,256)	3,158,586	-	-	-	-	-	-
12	903	8,721,804	(573,371)	8,148,433	1,365,563	(30,550)	1,335,013	1,572,645	(20,338)	1,552,307
13	905	245,780	(16,158)	229,622	-	-	-	-	-	-
14	908	181,489	(11,931)	169,558	-	-	-	-	-	-
15	909	-	-	-	-	-	-	-	-	-
16	910	517	(34)	483	-	-	-	-	-	-
17	920	-	-	-	-	-	-	29,919,071	(386,933)	29,532,138
18	922	-	-	-	-	-	-	-	-	-
19	930	-	-	-	-	-	-	29,786	(385)	29,401
20	SUBTOTAL	$36,601,011	$ (2,406,150)	$34,194,861	$ 2,516,775	$ (56,305)	$ 2,460,470	$31,521,502	$ (407,657)	$31,113,845
	MAINTENANCE									
21	885	$ 1,460,701	$ (96,026)	$ 1,364,675	$ 103,666	$ (2,319)	$ 101,347	$ -	$ -	$ -
22	886	9,036	(594)	8,442	-	-	-	-	-	-
23	887	4,945,102	(325,091)	4,620,011	-	-	-	-	-	-
24	889	736,861	(48,441)	688,420	-	-	-	-	-	-
25	892	3,503,130	(230,296)	3,272,834	-	-	-	-	-	-
26	893	742,977	(48,843)	694,134	-	-	-	-	-	-
27	894	99,171	(6,519)	92,652	-	-	-	-	-	-
28	935	448,253	(29,468)	418,785	-	-	-	184,361	(2,384)	181,977
29	SUBTOTAL	$11,945,231	$ (785,279)	$11,159,952	$ 103,666	$ (2,319)	$ 101,347	$ 184,361	$ (2,384)	$ 181,977
30	TOTALS	$48,546,242	$ (3,191,429)	$45,354,813	$ 2,620,441	$ (58,624)	$ 2,561,817	$31,705,863	$ (410,041)	$31,295,822

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANUALIZED LABOR LOADING

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		ARIZONA DIRECT			CORPORATE DIRECT			SYSTEM ALLOCATED		
LINE NO.	ACOUNT CODE	COMPANY AS FILED Co. WP, Adj. 3	RUCO ADJUSTMENT Pro Rated Pg 4	RUCO AS ADJUSTED Col. (A) - (B)	COMPANY AS FILED Co. WP, Adj. 3	RUCO ADJUSTMENT Pro Rated Pg 4	RUCO AS ADJUSTED Col. (D) - (E)	COMPANY AS FILED Co. WP, Adj. 3	RUCO ADJUSTMENT Pro Rated Pg 4	RUCO AS ADJUSTED Col. (G) - (H)
	OPERATIONS									
1	813	$ -	$ -	$ -	$ 216,923	$ (784)	$ 216,139	$ -	$ -	$ -
2	851	-	-	-	-	-	-	-	-	-
3	870	2,333,170	(22,673)	2,310,497	160,225	(579)	159,646	-	-	-
4	871	6,332	(62)	6,270	163,074	(590)	162,484	-	-	-
5	874	1,783,068	(17,327)	1,765,741	-	-	-	-	-	-
6	875	669,372	(6,505)	662,867	-	-	-	-	-	-
7	878	1,978,084	(19,222)	1,958,862	-	-	-	-	-	-
8	879	2,339,375	(22,733)	2,316,642	-	-	-	-	-	-
9	880	2,130,208	(20,701)	2,109,507	12,804	(46)	12,758	-	-	-
10	901	1,220,925	(11,865)	1,209,060	-	-	-	-	-	-
11	902	1,749,700	(17,003)	1,732,697	-	-	-	-	-	-
12	903	4,510,540	(43,832)	4,466,708	633,581	(2,291)	631,290	754,251	(16,217)	738,034
13	905	127,091	(1,235)	125,856	-	-	-	-	-	-
14	908	93,944	(913)	93,031	-	-	-	-	-	-
15	909	-	-	-	-	-	-	-	-	-
16	910	256	(2)	254	-	-	-	-	-	-
17	920	-	-	-	-	-	-	14,343,283	(308,390)	14,034,893
18	922	-	-	-	-	-	-	-	-	-
19	930	-	-	-	-	-	-	14,263	(307)	13,956
20	SUBTOTAL	$18,942,065	$ (184,074)	$18,757,991	$ 1,186,607	$ (4,290)	$ 1,182,317	$15,111,797	$ (324,913)	$14,786,884
	MAINTENANCE									
21	885	$ 755,990	$ (7,346)	$ 748,644	$ 53,906	$ (195)	$ 53,711	$ -	$ -	$ -
22	886	4,643	(45)	4,598	-	-	-	-	-	-
23	887	2,558,597	(24,864)	2,533,733	-	-	-	-	-	-
24	889	381,282	(3,705)	377,577	-	-	-	-	-	-
25	892	1,814,423	(17,632)	1,796,791	-	-	-	-	-	-
26	893	383,721	(3,729)	379,992	-	-	-	-	-	-
27	894	51,149	(497)	50,652	-	-	-	-	-	-
28	935	231,762	(2,252)	229,510	-	-	-	88,835	(1,910)	86,925
29	SUBTOTAL	$ 6,181,567	$ (60,071)	$ 6,121,496	$ 53,906	$ (195)	$ 53,711	$ 88,835	$ (1,910)	$ 86,925
30	TOTALS	$25,123,632	$ (244,144)	$24,879,488	$ 1,240,513	$ (4,485)	$ 1,236,028	$15,200,632	$ (326,823)	$14,873,809

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
REMOVING SALARIES OF SALES AND MARKETING EMPLOYEES

LINE NO.	ACCOUNT CODE	(A) DIRECT EMP'S SALARIES IN SALES/MRKT'G	(B) SYSTEM ALLOCABLE EMP'S SALARIES IN SALES/MRKT'G	(C) NO. OF EMPLOYEES
	INFORMATION FROM COMPANY RESPONSE TO RUCO DATA REQUEST NUMBER 2.08.b			
1		$ (76,567)		1
2		(75,965)		2
3		(71,972)		3
4		(69,784)		4
5		(85,440)		5
6		(76,898)		6
7		(76,026)		7
8		(67,153)		8
9		(71,879)		9
10		(83,776)		10
11		(93,764)		11
12		(100,608)		12
13			$ (84,367)	13
14			(99,256)	14
15			(89,679)	15
16			(78,026)	16
17			(85,794)	17
18			(72,339)	18
19			(91,792)	19
20			(91,424)	20
21			(87,373)	21
22			(99,226)	22
23		(58,385)		23
24		(62,896)		24
25		(70,924)		25
26		(72,660)		26
27		(76,949)		27
28		(67,338)		28
29		(67,842)		29
30		(73,103)		30
31		(67,348)		31
32		(70,584)		32
33		(82,998)		33
34		(86,966)		34
35		(93,299)		35
36		(103,221)		36
37		(120,921)		37
42	TOTALS	$ (2,125,266)	$ (879,276)	
43	ALLOCATION FACTOR	100.00%	87.25%	
44	ALLOCABLE TOTAL (See RLM-8, Page 3, Line 2)	$ (2,125,266)	$ (767,168)	$ (2,892,434)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 7
AMERICAN GAS ASSOCIATION (AGA) DUES

LINE NO	DESCRIPTION	(A) RUCO AS ADJUSTED
1	2004 AGA Dues (Company Schedule C-2, Adjustment No. 7)	$ 384,566
	Less:	
2	Paiute And SGTC Allocation Factor (Company Schedule C-1, Sheet 19)	-4.29%
3	Paiute And SGTC Allocation (Line 1 X Line 2)	(16,498)
4	Adjustment To AGA Dues Before 4-Factor (Line 1 + Line 3)	$ 368,068
5	System Allocation Factor (Company Schedule C-1, Sheet 18)	57.58%
6	Arizona AGA Dues (Line 4 X Line 5)	$ 211,934
7	Adjustment To Remove Lobbying And Adverising Portion Of SWG's AGA Dues Percent Disallowed (See NOTE A)	39.09%
8	Subtotal (Line 6 x Line 7)	$ 82,845
	Less:	
9	Amount Removed By SWG (Company Schedule C-2, Adjustment No. 7)	7,460
10	RUCO ADJUSTMENT TO SWG's AGA DUES (Line 8 - Line 9) (See RLM-7, Page 1, Column (E))	$ 75,385

NOTE A

As Per Company Response To RUCO Data Request No. 14.2
Categories Of Disallowance:

			Percentage
11		Public Affairs	23.35%
12		Communications	15.74%
13	Total		39.09%

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 10
INJURIES AND DAMAGES - SELF INSURED RETENTION NORMALIZATION

LINE NO	DESCRIPTION	REFERENCE	(A) 14 YEAR TOTAL	(B) TOTAL AZ ACCRUAL
1	Claims Paid			
2	< $1,000,000	Response To RUCO DR 14	$ 8,557,891	
3	At $1,000,000	Response To RUCO DR 14	10,000,000	
4	> $1,000,000 < $10,000,000	Response To RUCO DR 14 (less claims over $10 M)	27,547,300	
5	Total Claims Paid	(Sum Of Lines 2, 3 & 4)	$ 46,105,191	
6	14 Year Average	Line 5 / 14 Years		$ 3,293,228
	Less:			
7	FERC Allocation Factor	Co. Sch. C-1, Sh 18		4.29%
8	FERC Allocation	Line 6 X Line 7		(141,279)
9	Net System Allocable	Sum Of Lines 6 & 8		$ 3,151,948
10	Arizona 4-Factor	Co. Sch. C-1, Sh 19		57.58%
11	Net Arizona Allocated	Line 9 X Line 10		$ 1,814,892
12	Company Injuries And Damages Expenses As Filed	Sch. C-2, Adj. No. 10, Column (f), Line 8		$ 2,161,296
13	Difference	Line 11 - Line 12		$ (346,404)
14	RUCO ADJUSTMENT TO INJURIES AND DAMAGES EXPENSE (See RLM-7, Page 1, Column (G))			$ (346,404)

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 14
MISCELLANEOUS ADJUSTMENTS

		(A)	(B)	(C)	(D)
		RUCO ADJUSTMENTS			
LINE NO	DESCRIPTION	ALLOCABLE TOTAL	ALLOC'N FACTOR	ARIZONA TOTAL	RUCO AS ADJUSTED
	Arizona Direct Accounts				
1	870 - Operation Supervision And Engineering	$ (25,337)	100.00%	$ (25,337)	
2	875 - Measuring And Regulating Expenses - General	N/A	100.00%	-	
3	880 - Other Expenses	(162,828)	100.00%	(162,828)	
4	Sub Total Distribution	$ (188,165)			$ (188,165)
5	902 - Meter Reading	$ (10,715)	100.00%	$ (10,715)	
6	903 - Customer Records And Collection Expenses	N/A	100.00%	-	
7	Sub Total Customer Accounts	$ (10,715)			$ (10,715)
8	908 - Customer Assistance Expenses	N/A	100.00%	$ -	
9	910 - Miscellaneous Customer Service And Information Expenses	N/A	100.00%	-	
10	Sub Total Customer Service And Information Expenses	$ -			$ -
11	Sub Total Arizona Direct Accounts	$ (198,880)			$ (198,880)
	System Allocable Accounts To Arizona				
12	903 - Customer Records And Collection Expenses	N/A	55.40%	$ -	
13	Sub Total Customer Accounts	$ -			$ -
14	921 - Office Supplies And Expenses	$ (170,593)	57.58%	$ (98,227)	
16	923 - Outside Services Employed	(27,768)	57.58%	(15,989)	
17	930 - Miscellaneous General Expenses	(57,664)	57.58%	(33,203)	
18	Sub Total Administrative And General Expenses	$ (256,025)			$ (147,419)
19	Sub Total System Allocable Accounts To Arizona	$ (256,025)			$ (147,419)
20	RUCO ADJUSTMENT TO MISCELLANEOUS ADJUSTMENTS (See RLM-7, Page 1, Column (I))				$ (346,299)

References:
Column (A): See Testimony, RLM
And Workpapers RLM-11WP(870) Pages 1 To 4, RLM-11WP(880) Pages 1 To 18, RLM-11WP(902) Pages 1 To 3, RLM-11WP(921) Pages 1 To 13, RLM11-WP(923) Page 1, RLM-11WP(930) Page 1
Column (B): Company Schedule C-2, Adjustment No. 14
Column (C): Column (A) X Column (B)
Column (D): Sums Of Column (C)

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Schedule RLM-12

EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 17
DIRECT PLANT TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.		(A) TOTAL PLANT VALUE	(B) CO. PROPOSED DEPRECIATION RATE	(C) TEST YEAR DEPREC'N EXPENSE
		Intangible Plant:			
1	301	Organization	$ 42,653	Amortized	$ -
2	302	Franchises & Consents	1,714,402	Amortized	77,626
3	303	Miscellaneous Intangible	1,945,631	Amortized	132,362
4		Total Intangible Plant	$ 3,702,686		$ 209,988
		Distribution Plant:			
5	374.1	Land & Land Rights	$ 351,685	0.00%	$ -
6	374.2	Rights Of Way	720,979	2.15%	15,501
7	375	Structures	110,557	1.15%	1,271
8	376	Mains	786,937,551	3.82%	30,061,014
9	378	Measuring & Regulating Station	24,454,990	4.12%	1,007,546
10	380	Services	522,687,054	5.30%	27,702,414
11	381	Meters	156,809,964	1.98%	3,104,837
12	385	Industrial Measuring & Regulating Station	6,528,499	4.31%	281,378
13	387	Other Equipment	462,730	5.26%	24,340
14		Total Distribution Plant	$ 1,499,064,009		$ 62,198,302
		General Plant:			
15	389	Land & Land Rights	$ 6,454,589	0.00%	$ -
16	390.1	Structures	26,285,123	1.84%	483,646
17	390.2	Structures - Leasehold Improvments	1,005,567	Amortized	62,345
18	391	Office Furniture And Equipment	4,849,827	2.73%	132,400
19	391.1	Computer Equipment	8,489,038	14.87%	1,262,320
20	392.1	Transportation Equipment	30,447,147	7.65%	2,329,207
21	393	Stores Equipment	481,909	2.08%	10,024
22	394	Tools, Shop And Garage Equipment	4,891,998	2.17%	106,156
23	395	Laboratory Equipment	425,322	3.93%	16,715
24	396	Power Operated Equipment	3,807,547	3.88%	147,733
25	397	Communication Equipment	2,223,684	8.88%	197,463
26	397.2	Telemetering Equipment	560,307	6.19%	34,683
27	398	Miscellaneous Equipment	844,186	4.53%	38,242
28		Total General Plant	$ 90,766,244		$ 4,820,934
29		TOTAL DIRECT PLANT	$ 1,593,532,939		$ 67,229,224
30		Company Direct Plant As Filed	1,597,358,113		67,338,861
31		Difference	(3,825,174)		$ (109,637)
32		RUCO ADJUSTMENT TO TEST YEAR DIRECT DEPRECIATION EXPENSE (See RLM-7, Page 2, Column (J))			$ (109,637)

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 17 - CONT'D
SYSTEM ALLOCABLE PLANT TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.		(A) TOTAL PLANT VALUE	(B) CO. PROPOSED DEPRECIATION RATE	(C) TEST YEAR DEPREC'N EXPENSE
		Intangible Plant:			
1	301.0	Organization	$ 61,816	0.00%	$ -
2	302.0	Franchises & Consents	-	Amortized	-
3	303.0	Miscellaneous Intangible	105,328,240	Amortized	# 7,977,861
4		Total Intangible Plant	$ 105,390,056		$ 7,977,861
		Distribution Plant:			
5	374.1	Land & Land Rights	$ -	0.00%	$ -
6	374.2	Rights Of Way	-	0.00%	-
7	375.0	Structures	-	0.00%	-
8	376.0	Mains	-	0.00%	-
9	378.0	Measuring & Regulating Station	-	0.00%	-
10	380.0	Services	-	0.00%	-
11	381.0	Meters	-	0.00%	-
12	385.0	Industrial Measuring & Regulating Station	-	0.00%	-
13	387.0	Other Equipment	-	0.00%	-
14		Total Distribution Plant	$ -		$ -
		General Plant:			
15	389.0	Land & Land Rights	$ 391,307	0.00%	$ -
16	390.1	Structures	11,831,108	2.50%	295,778
17	390.2	Structures - Leasehold Improvments	3,144,329	Amortized	29,729
18	391.0	Office Furniture And Equipment	7,751,650	8.16%	632,535
19	391.1	Computer Equipment	13,445,898	16.15%	2,171,513
20	392.1	Transportation Equipment	3,338,897	7.20%	240,401
21	393.0	Stores Equipment	111,293	7.20%	8,013
22	394.0	Tools, Shop And Garage Equipment	7,386	16.03%	1,184
23	395.0	Laboratory Equipment	414,693	11.16%	46,280
24	396.0	Power Operated Equipment	268,894	4.77%	12,826
25	397.0	Communication Equipment	4,605,689	8.51%	391,944
26	397.2	Telemetering Equipment	401,430	40.23%	161,495
27	398.0	Miscellaneous Equipment	934,686	11.09%	103,657
28		Total General Plant	$ 46,647,260		$ 4,095,354
29		TOTAL ALLOCABLE PLANT	$ 152,037,316		$ 12,073,215
31		Company As Filed	$ 153,085,151		$ 12,265,743
32		Difference	$ (1,047,835)		$ (192,528)
30		Allocation Factor	57.58%		57.58%
31		ALLOCATED PLANT	$ (603,341)		$ (110,857)

32	RUCO ADJUSTMENT TO TEST YEAR SYSTEM ALLOCATED DEPRECIATION (See RLM-7, Page 2, Column (J))	$ (110,857)

NOTE: AMOUNT IN COLUMN (C), LINE 3 INCLUDES THE ADJUSTMENT FROM SCHEDULE MDC-6

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 18
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	(A)	(B)
	Calculation Of The Company's Full Cash Value:		
1	Net Plant In Service		$ 1,047,658,883
	ADD:		
2	Materials And Supplies (Company Schedule B-5, Sheet 1, Column (c), Line 2)	9,222,489	
3	Total (Line 2)		$ 9,222,489
	SUBTRACT:		
4	Original Cost Of Trans Equip (RLM-3, Pg 1, Col (M), L 20 + Pg 2, Col (M), L 20 + L 21)	$ 33,897,337	
5	Acc. Dep. Of Trans Equip (RLM-3, Pg 1, Col (N), L 20 + Pg 2, Col (N), L 20 + L 21)	$ 6,354,715	
6	Book Value Of Transportation Equipment (Line 5 - Line 6 Expressed In The Negative)		$ (27,542,622)
7	Land Rights (Company Sch. C-2, Adj. 18)		$ (797,670)
8	COMPANY'S FULL CASH VALUE (Sum Of Lines 1, 3, 6 & 7)		$ 1,028,541,080
	Calculation Of The Company's Tax Liability:		
	MULTIPLY: Company Full Cash Value By Valuation Assessment Ratio And Then By Property Tax Rates:		
9	Assessment Ratio (Per House Bill 2779)	24.5%	
10	Assessed Value (Line 8 X Line 9)	$ 251,992,565	
	Property Tax Rates:		
11	Primary Tax Rate (2004 Tax Notice - Co.'s Data Response - "Property Tax")	12.77%	
12	Secondary Tax Rate (2004 Tax Notice - Co.'s Data Response - "Property Tax")	0.00%	
13	Estimated Tax Rate Liability (Line 11 + Line 12)	12.77%	
14	COMPANY'S TAX LIABILITY - Based On Full Cash Value (Line 10 X Line 13)		$ 32,179,450
15	Test Year Adjusted Property Tax Expense Per Company's Filing (Co. Sch. C-2, Adj No. 18))	$ 33,447,313	
16	Increase (Decrease) In Property Tax Expense (Line 14 - Line 15)	$ (1,267,863)	
17	RUCO ADJUSTMENT TO PROPERTY TAX EXPENSE (See RLM-7, Page 2, Column (K))		$ (1,267,863)

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Schedule RLM-14
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EXPLANATION OF RUCO OPERATING INCOME ADJUSTMENT NO. 21
SUPPLEMENTAL EMPLOYEE RETIREMENT PLAN

LINE NO	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO AS ADJUSTED	(C) DISTRIBUTION PERCENTAGE	(D) RUCO ADJUSTMENT
	ALLOCATIONS:	WP C-2, Adj #3, Sh 8, L 11	Col (A) + Col (D)	WP C-2, Adj #3, Sh 8, L 13	Distributed Total RUCO DR 14-1.a
1	Arizona	$ 2,109,491	$ 979,554	41.93%	$ (1,129,937)
2	Corporate Direct	97,085	45,082	1.93%	(52,003)
3	Other Jurisdictions	1,578,657	733,058	31.38%	(845,599)
4	System Allocable	1,245,471	578,342	24.76%	(667,129)
5	Total (Sum Of Lines 1, 2, 3 & 4)	$ 5,030,704	$ 2,336,036	100.00%	$ (2,694,668)

FUNCTIONALIZATION:

LINE NO	DESCRIPTION	DISTRIBUTION PRECENTAGE See NOTE A	DISTRIBUTION Of Col (D), Line 1	ALLOCATION FACTOR	RUCO ADJUSTMENT RLM-7, Pg 2, Col (M)
6	OTHER GAS SUPPLY (813)	0.87%	$ (9,815)	100.00%	$ (9,815)
7	DISTRIBUTION (870-880 & 885-894)	65.12%	(735,813)	100.00%	(735,813)
8	CUST. ACC'TS (901, 902, 903 & 905)	33.66%	(380,369)	100.00%	(380,369)
9	CUST. SER. & INFO (908, 909, & 910)	0.35%	(3,939)	100.00%	(3,939)
10	SUBTOTAL Sum Of Lines 6 Thru 9)	100.00%	(1,129,937)		
11	SALES				-
	ADMINISTRATION & GENERAL		DISTRIBUTION Of Col (D), L 2 & L4		
12	CORPORATE DIRECT (935)		(52,003)	100.00%	(52,003)
13	SYS. ALLOC. (920, 922, 930 & 935)		(667,129)	57.58%	(384,133)
14	TOTAL (Sum Of Lines 10, 12 & 13) (See RLM-7, Pg 2, Col (M))		$ (1,849,069)		$ (1,566,073)

NOTE A

To Determine The Distribution Ratio Of Arizona Direct SERP
By Allocating Expenses At The Same Percentage As Labor Loading In Adjustment No. 3

LINE NO	DESCRIPTION	ADJ'MENT NO.3 RLM-8, PG 1	DISTRIBUTION PRECENTAGE
15	OTHER GAS SUPPLY (813)	$ 671,971	0.87%
16	DISTRIBUTION (870-880 & 885-894)	50,376,691	65.12%
17	CUST. ACC'TS (901, 902, 903 & 905)	26,041,593	33.66%
18	CUST. SER. & INFO (908, 909, & 910)	269,705	0.35%
19	SUBTOTAL	77,359,960	100.00%

EXPLANATION OF OPERATING INCOME ADJUSTMENT
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Schedule RLM-6, Column (C), Line 18 + Line 16	$ 59,317,635
	LESS:		
2	Arizona State Tax	Line 11	(1,592,748)
3	Interest Expense	Note (A) Line 21	(36,459,599)
4	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$ 21,265,289
5	Federal Tax Rate	Schedule RLM-1, Page 2, Column (A), Line 10	35.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 7,442,851
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 59,317,635
	LESS:		
8	Interest Expense	Note (A) Line 21	(36,459,599)
9	*State Taxable Income*	Line 7 + Line 8	$ 22,858,037
10	State Tax Rate	Tax Rate	6.9680%
11	State Income Tax Expense	Line 9 X Line 10	$ 1,592,748
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 7,442,851
13	State Income Tax Expense	Line 11	1,592,748
14	South Georgia Amortization	Company Schedule C-1, Sheet 17, Column (C), Line 8 + Line 18	365,253
15	Investment Tax Credit	Company Schedule C-1, Sheet 17, Column (C), Line 19	(528,352)
16	Total Income Tax Expense Per RUCO	Sum Of Lines 12, 13, 14 & 15	$ 8,872,500
17	Total Income Tax Expense Per Company Filing (Schedule C-1)		2,156,664
18	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See RLM 7, Page 2, Column (Q))	Line 16 - Line 17	$ 6,715,836

NOTE (A):
Interest Synchronization:

LINE NO.	DESCRIPTION	AMOUNT
19	Adjusted Rate Base (Schedule RLM-2, Column (C), Line 10)	$ 918,447,207
20	Weighted Cost Of Debt (Schedule RLM-18, Column (F), Line 1 + Line 2)	3.97%
21	Interest Expense (Line 19 X Line 20)	$ 36,459,599

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RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	(A) DESCRIPTION	(B) PROPOSED SCHEDULE NO.	(C) BILLING DETERMINANTS NUMBER OF BILLS	(D) BILLING DETERMINANTS SALES (THERMS)	(E) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(F) PROPOSED MARGIN RATES COMMODITY CHARGE	(G) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(H) MARGIN AT PROPOSED RATES COMMODITY CHARGE	(I) TOTAL MARGIN
	Single-Family Residential Gas Service	G-5							
1	Basic Service Charge per Month		9,563,921		$ 9.36		$ 89,520,069		$ 89,520,069
2	Commodity Charge All Therms			265,765,100		0.487185		129,476,751	129,476,751
3	Total Single-Family Residential Gas Service		9,563,921	265,765,100			$ 89,520,069	$ 129,476,751	$ 218,996,820
	Low Income Residential Gas Service	G-5							
4	Basic Service Charge per Month		345,978		9.36		$ 3,238,420		$ 3,238,420
5	Commodity Charge All Therms			9,553,429		0.487185		4,654,287	4,654,287
						0.487185		-	-
6	Total Low Income Residential Gas Service		345,978	9,553,429			$ 3,238,420	$ 4,654,287	$ 7,892,707
	Multi-Family Residential Gas Service	G-6							
7	Basic Service Charge per Month		748,946		8.19		$ 6,133,989		$ 6,133,989
8	Commodity Charge All Therms			14,987,992		0.487185		7,301,924	7,301,924
						0.487185		-	-
9	Total Multi-Family Residential Gas Service		748,946	14,987,992			$ 6,133,989	$ 7,301,924	$ 13,435,912
	Multi-Family Low Income Residential Gas Service	G-6							
10	Basic Service Charge per Month		55,465		8.19		$ 454,269	$ -	$ 454,269.09
11	Commodity Charge All Therms			1,213,156		0.487185		591,031.30	591,031.30
						0.487185		-	-
12	Total Multi-Family Low-Income Gas Service		55,465	1,213,156			$ 454,269	$ 591,031	$ 1,045,300
13	Total Residential Gas Service		10,714,311	291,519,677			99,346,747	142,023,993	241,370,740
	Master Metered Mobile Home Park Gas Service	G-20							
30	Basic Service Charge per Month		2,462		$ 127.35		$ 313,589		$ 313,589
31	Commodity Charge per Therm			2,505,221		0.283626		710,545	710,545
32	Total Master Metered Mobile Home Park Gas Service		2,462	2,505,221			313,589	710,545	1,024,134
	General Gas Service - Small	G-25(S)							
	Basic Service Charge per Month								
1	Former Small Gas Service Customers		214,764		$ 31.84		$ 6,837,667		$ 6,837,667
2	Former Medium Gas Service Customers		104		$ 31.84		3,318		3,318
3	Former Essential Agriculture Customers		156		$ 31.84		4,978		4,978
	Commodity Charge per Therm								
4	Transportation Customers			643		0.607100		390	390
5	Sales Customers			3,867,813		0.607100		2,348,150	2,348,150
6	Total Small General Gas Service		215,024	3,868,456			$ 6,845,963	$ 2,348,540	$ 9,194,503

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		PROPOSED	BILLING DETERMINANTS		PRESENT MARGIN RATES			MARGIN AT PRESENT RATES	
LINE NO.	DESCRIPTION	SCHEDULE NO.	NUMBER OF BILLS	SALES (THERMS)	BASIC SERVICE CHARGE	COMMODITY CHARGE	BASIC SERVICE CHARGE	COMMODITY CHARGE	TOTAL MARGIN
	General Gas Service - Medium	G-25(M)							
	Basic Service Charge per Month								
7	Former Small Gas Service Customers		207,728		$ 44.57		$ 9,259,145		$ 9,259,145
8	Former Medium Gas Service Customers		4,026		44.57		179,442		179,442
9	Former Large Gas Service Customers		13		44.57		581		581
10	Former Armed Forces Customers		26		44.57		1,161		1,161
11	Former Essential Agriculture Customers		560		44.57		24,971		24,971
	Commodity Charge per Therm								
	Transportation Customers								
12	Former Small Gas Service Customers			103,604		0.352337		36,504	36,504
13	Former Medium Gas Service Customers			87,082		0.352337		30,682	30,682
	Sales Customers			-					
14	Former Small Gas Service Customers			41,835,599		0.352337		14,740,233	14,740,233
15	Former Medium Gas Service Customers			1,782,746		0.352337		628,127	628,127
16	Former Large Gas Service Customers			5,159		0.352337		1,818	1,818
17	Former Armed Forces Customers			3,930		0.352337		1,385	1,385
18	Former Essential Agriculture Customers			136,422		0.352337		48,067	48,067
19	Total Medium General Gas Service		212,353	43,954,541			$ 9,465,300	$ 15,486,814	$ 24,952,114
	General Gas Service - Large	G-25(L)							
	Basic Service Charge per Month								
20	Former Small Gas Service Customers		4,750		$ 191.03		$ 907,375		$ 907,375
21	Former Medium Gas Service Customers		86,187		191.03		16,464,241		16,464,241
22	Former Large Gas Service Customers		130		191.03		24,888		24,888
23	Former Armed Forces Customers		26		191.03		4,978		4,978
	Commodity Charge per Therm								
	Transportation Customers								
24	Former Small Gas Service Customers			83,642		0.240806		20,141	20,141
25	Former Medium Gas Service Customers			2,754,626		0.240806		663,331	663,331
26	Former Large Gas Service Customers			323,190		0.240806		77,826	77,826
	Sales Customers			-					
27	Former Small Gas Service Customers			3,002,106		0.240806		722,926	722,926
28	Former Medium Gas Service Customers			137,636,528		0.240806		33,143,743	33,143,743
29	Former Large Gas Service Customers			1,078,065		0.240806		259,605	259,605
30	Former Armed Forces Customers			172,404		0.240806		41,516	41,516
31	Total Large General Gas Service		91,094	145,050,561			$ 17,401,482	$ 34,929,090	$ 52,330,572
	General Gas Service - Transportation Eligible	G-25(TE)							
	Basic Service Charge per Month								
32	Former Medium Gas Service Customers		65		$ 955.14		$ 62,220		$ 62,220
33	Former Essential Agriculture Customers		274		955.14		261,324		261,324
34	Former Large Gas Service Customers		1,824		955.14		1,742,160		1,742,160
35	Former Armed Forces Customers		65		955.14		62,220		62,220
36	Demand Charge Per Month			10,571,934		0.055057		6,984,770	6,984,770
	Commodity Charge per Therm								
	Transportation Customers								
37	Former Medium Gas Service Customers					0.081403		-	-
38	Former Essential Agriculture Customers			4,529,656		0.081403		368,725	368,725
39	Former Large Gas Service Customers			26,387,348		0.081403		2,147,997	2,147,997
	Sales Customers			-					
40	Former Medium Gas Service Customers			1,037,977		0.081403		84,494	84,494
41	Former Essential Agriculture Customers			5,172,762		0.081403		421,076	421,076
42	*Former Large Gas Service Customers*			47,458,640		0.081403		3,863,253	3,863,253
43	Former Armed Forces Customers			3,059,260		0.081403		249,031	249,031
44	Total Transportation Eligible General Gas Service		2,228	87,645,643			$ 2,127,924	$ 14,119,347	$ 16,247,271
45	Total General Gas Service		520,699	280,519,200	-	-	$ 35,840,669	$ 66,883,790	$ 102,724,459

Southwest Gas Corporation
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	(A) DESCRIPTION	(B) PROPOSED SCHEDULE NO.	(C) BILLING DETERMINANTS NUMBER OF BILLS	(D) BILLING DETERMINANTS SALES (THERMS)	(E) PRESENT MARGIN RATES BASIC SERVICE CHARGE	(F) PRESENT MARGIN RATES COMMODITY CHARGE	(G) MARGIN AT PRESENT RATES BASIC SERVICE CHARGE	(H) MARGIN AT PRESENT RATES COMMODITY CHARGE	(I) TOTAL MARGIN
	Air Conditioning Gas Service	G-40							
	Basic Service Charge								
1	With Other Service (No Basic Service Charge)		65		$ -		$ -		$ -
2	Basic Service Charge		422		31.84		13,446		13,446
	Commodity Charge per Therm								
3	Transportation Customers			642,426		0.089717		57,636	57,636
4	Sales Customers			1,233,591		0.089717		110,674	110,674
5	Total Air Conditioning Gas Service		487	1,876,017			$ 13,446	$ 168,310	$ 181,757
	Street Lighting Gas Service	G-45							
	Commodity Charge per Therm Of Rated Capacity								
6	All Usage		378	102,030	$ -	$ 0.510274	$ -	$ 52,063	$ 52,063
7	Total Street Lighting Gas Service		378	102,030			$ -	$ 52,063	$ 52,063
	Gas Service For Compression On Customer's Premises	G-55							
	Basic Service Charge								
8	Small		287		$ 31.84	$ -	$ 9,126	$ -	$ 9,126
9	Large		352		445.73		156,794		156,794
10	*Residential*		1,433		9.36		13,414		13,414
	Commodity Charge per Therm								
11	Transportation Customers			-		0.11799		-	-
	Sales Customers			-					
12	Small			186,231		0.11799		21,974	21,974
13	Large			1,939,619		0.11799		228,857	228,857
14	Residential			81,432		0.11799		9,608	9,608
15	Total Gas Service For Compression On Customer's Premises		2,072	2,207,283			$ 179,334	$ 260,439	$ 439,773
	Electric Generation Gas Service	G-60							
	Basic Service Charge								
16	General Service - Small		65		$ 31.84		$ 2,074		$ 2,074
17	General Service - Medium		-		44.57		-		-
18	General Service - Large		104		191.03		19,910		19,910
19	General Service - Transportation Eligible		104		955.14		99,552		99,552
20	Essential Agriculture		26		191.03		4,978		4,978
	Commodity Charge per Therm								
21	Transportation Customers			-		0.08954		-	-
22	Sales Customers			15,330,306		0.08954		1,372,691	1,372,691
23	Total Electric Generation Gas Service		300	15,330,306			$ 126,514	$ 1,372,691	$ 1,499,205
	Small Essential Agriculture User Gas Service	G-75							
24	Basic Service Charge		472		$ 191.03		$ 90,219	$ -	$ 90,219
	Commodity Charge per Therm								
25	Transportation Customers			159,244		0.19499		31,051	31,051
26	Sales Customers			2,849,131		0.19499		555,552	555,552
27	Total Small Essential Agriculture Gas Service		472	3,008,375			$ 90,219	$ 586,602	$ 676,821
	Natural Gas Engine Gas Service	G-80							
	Basic Service Charge								
28	Off-Peak Season (October - March)		3,933		$ -	$ -	$ -	$ -	$ -
29	On-Peak Season (April - September)		3,933		127.35		500,821		500,821
	Commodity Charge per Therm								
30	Transportation Customers			-		0.13929		-	-
31	Sales Customers			21,728,560		0.13929		3,026,485	3,026,485
32	Total Natural Gas Engine Gas Service		7,866	21,728,560			$ 500,821	$ 3,026,485	$ 3,527,306
33	Total Tariff Sales		11,249,047	618,796,668			136,411,339	215,084,918	351,496,257
34	Optional Gas Service	G-30	352	103,831,824	$ 1,576.36	0.04951	$ 554,511	$ 5,140,758	$ 5,695,269
35	Special Contract Service	*B-1*	294	*31,064,410*	$ *681.56*	*0.06413*	$ 200,532	$ *1,992,049*	$ 2,192,581
36	Other Operating Revenues						$ 11,434,480		$ 11,434,480
37	Total Revenue		11,249,693	753,692,902			$ 148,600,862	$ 222,217,725	$ 370,818,588
38	Recommended Annual Revenue Requirement								$ 370,818,589
39	Difference								$ (1)

TYPICAL BILL ANALYSIS
SINGLE-FAMILY RESIDENTAL GAS SERVICE

COMPARISON OF PRESENT & PROPOSED RATE STRUCTURE

LINE NO.	DESCRIPTION	CONSP'TION (THERMS)	PRESENT SCHEDULES	PROPOSED SCHEDULES	DOLLAR INCREASE	PERCENT INCREASE
			SUMMER			
			May-October Break - 20 Therms	May-October Break - 8 Therms		
	Company					
1	25% Average Usage	3	$ 11.19	$ 19.74	$ 8.55	76.43%
2	75% Average Usage	9	$ 17.57	$ 26.52	$ 8.95	50.97%
3	Average Usage	12	$ 20.76	$ 28.66	$ 7.90	38.06%
4	150% Average Usage	19	$ 27.14	$ 32.93	$ 5.79	21.35%
5	200% Average Usage	25	$ 33.10	$ 37.20	$ 4.10	12.40%
	RUCO					
6	25% Average Usage	3	$ 11.07	$ 12.43	$ 1.36	12.27%
7	75% Average Usage	9	$ 17.22	$ 18.58	$ 1.36	7.88%
8	Average Usage	12	$ 20.29	$ 21.65	$ 1.35	6.68%
9	150% Average Usage	18	$ 26.44	$ 27.79	$ 1.35	5.11%
10	200% Average Usage	24	$ 32.59	$ 33.93	$ 1.35	4.14%
			SWING MONTHS			
			April & November Break - 40 Therms	April & November Break - 8 Therms		
	Company					
11	25% Average Usage	11	$ 19.59	$ 19.74	$ 0.16	0.79%
12	75% Average Usage	34	$ 42.76	$ 26.52	$ (16.23)	-37.97%
13	Average Usage	45	$ 53.90	$ 28.66	$ (25.23)	-46.82%
14	150% Average Usage	68	$ 75.16	$ 32.93	$ (42.23)	-56.18%
15	200% Average Usage	91	$ 96.42	$ 37.20	$ (59.22)	-61.42%
	RUCO					
16	25% Average Usage	11	$ 19.46	$ 20.81	$ 1.36	6.97%
17	75% Average Usage	34	$ 42.37	$ 43.71	$ 1.35	3.18%
18	Average Usage	45	$ 53.41	$ 55.16	$ 1.75	3.27%
19	150% Average Usage	67	$ 74.44	$ 78.06	$ 3.63	4.87%
20	200% Average Usage	90	$ 95.46	$ 100.96	$ 5.50	5.76%
			WINTER			
			December-March Break - 40 Therms	December-March Break - 30 Therms		
	Company					
21	25% Average Usage	11	$ 19.59	$ 29.59	$ 10.01	51.09%
22	75% Average Usage	34	$ 42.76	$ 54.71	$ 11.95	27.95%
23	Average Usage	45	$ 53.90	$ 62.47	$ 8.58	15.91%
24	150% Average Usage	68	$ 75.16	$ 77.99	$ 2.83	3.76%
25	200% Average Usage	91	$ 96.42	$ 93.51	$ (2.92)	-3.03%
	RUCO					
26	25% Average Usage	11	$ 19.46	$ 20.81	$ 1.36	6.97%
27	75% Average Usage	34	$ 42.37	$ 43.71	$ 1.35	3.18%
28	Average Usage	45	$ 53.41	$ 55.16	$ 1.75	3.27%
29	150% Average Usage	67	$ 74.44	$ 78.06	$ 3.63	4.87%
30	200% Average Usage	90	$ 95.46	$ 100.96	$ 5.50	5.76%
	PROPOSED AVERAGE RESIDENTIAL TOTAL ANNUAL GAS SERVICE COSTS					
31	**Company**		$ 447.93	$ 479.17	$ 31.24	6.97%
32	**RUCO**		$ 442.24	$ 460.85	$ 18.62	4.21%
	PRO-RATED AVERAGE RESIDENTIAL MONTHLY GAS SERVICE COSTS (ANNUAL COSTS DIVIDED BY 12 MONTHS)					
33	**Company**		$ 37.33	$ 39.93	$ 2.60	6.97%
34	**RUCO**		$ 36.85	$ 38.40	$ 1.55	4.21%

RATE SCHEDULES

PRESENT BASIC SERVICE

$ 8.00

PRESENT COMMODITY RATE

1.02198 *
0.9378 *

BREAKPOINTS

SUMMER (THERMS) (May - Oct)
20

WINTER (THERMS) (May - Oct)
40

PROPOSED RATE DESIGNS

	COMPANY	**RUCO**
BASIC SERVICE	$ 16.00	$ 9.36
COMMODITY RATE	1.1989 * 0.68436 *	1.02154 *
BREAKPOINTS		
SUMMER (THERMS) (Apr - Nov)	8	N/A
WINTER (THERMS) (Dec - Mar)	30	N/A

* - The Commodity Rate Includes Gas Costs Of $0.05346 Per Therm

Southwest Gas Corporation
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Short-term Debt	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	Long-term Debt	$ 785,950,234	$ -	$ 785,950,234	53.00%	7.49%	3.97%
3	Preferred Stock	$ 100,000,000	$ -	$ 100,000,000	5.00%	8.20%	0.41%
4	Common Equity	$ 662,978,685	$ -	$ 662,978,685	42.00%	10.15%	4.26%
5	TOTAL CAPITAL	$ 1,548,928,919	$ -	$ 1,548,928,919	100.00%		
6	COST OF CAPITAL						8.64%

References:
- Column (A): Company Schedule D-1
- Column (B): Testimony, WAR
- Column (C): Column (A) + Column (B)
- Column (D): Column (C), Line Item / Total Capital (L5)
- Column (E): Testimony, WAR
- Column (F): Column (D) X Column (E)

EXHIBIT
tabbies
RUCO-6
Admitted

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-04-0876

SURREBUTTAL TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

SEPTEMBER 13, 2005

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name for the record.

A. My name is Rodney Lane Moore.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on July 26, 2005.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the Company's rebuttal comments pertaining to adjustments I sponsored in my direct testimony.

SUMMARY OF ADJUSTMENTS

Q. What areas will you address in your surrebuttal testimony?

A. My surrebuttal testimony will address the following RUCO proposed adjustments:

1. Correction for computation error in calculating bill determinants for RUCO rate design as shown on Schedule RLM-16, pages 1, 2 and 3;
2. Rate Base Adjustment No. 3 – Completed Construction Not Classified;
3. Operating Income Adjustment No. 3 – Labor Annualization;
4. Operating Income Adjustment No. 7 – American Gas Association Dues;

5. Operating Income Adjustment No. 10 – Injuries and Damages;
6. Operating Income Adjustment No. 14 – Miscellaneous;
7. Operating Income Adjustment No. 18 – Property Tax Expense;
8. Operating Income Adjustment No. 21 – Supplemental Employee Retirement Plan;
9. Income Tax Calculation; and
10. Rate Design and Proof of Recommended Revenue.

To support the adjustments to my surrebuttal testimony, I revised Direct Schedules RLM-16, RLM-17 and prepared eleven sets of Surrebuttal Schedules numbered SUR-RLM-1, SUR-RLM-2, SUR-RLM-3, SUR-RLM-5, SUR-RLM-6, SUR-RLM-7, SUR-RLM-8, SUR-RLM-10, SUR-RLM-11, SUR-RLM-16 and SUR-RLM-17, which are filed concurrently in my surrebuttal testimony.

REVISED DIRECT TESTIMONY FOR SCHEDULE RLM-16

Q. What is the computation error you are correcting in this revised filing of Schedule RLM-16?

A. First, as shown on the attached revised Schedule RLM-16, columns (C) and (D), I adjusted the bill determinants to reflect a more accurate allocation between residential and general service customers.

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This revision was the result of discussions with the Company and directly correlates the bill frequency analysis ("BFA") of the existing test year residential customer base at the present rate structure with the Company's proposed rate structure.

Second, as shown on Schedule RLM-16, columns (E) and (F), RUCO adjusted the basic monthly service charges and margin commodity rates to produce RUCO's recommended revenue requirement through the revised bill determinants.

RUCO'S ADJUSTED TEST PERIOD BILLS AND VOLUMES

Q. Did RUCO adjust the Company's bills and volumes as filed on Schedule H-2, page 16?

A. Yes, as stated in my direct testimony, I had to make adjustments to the bill determinants to correctly produce test-year revenues.

Q. Why does the Company disagree with your adjustment to the bills and volumes as filed?

A. In Company witness Mr. Congdon's rebuttal testimony, starting on page 24, Mr. Congdon indicates SWG multiplied present rates and charges by the recorded bills and volumes and was able to recalculate residential test-year revenue to within 0.03 percent, as shown on Company Rebuttal Exhibit ABC-4, sheet 3, line 1.

The bills and volumes used on the Company's Rebuttal Exhibit ABC-4, sheet 3, line 1 are the same adjusted bills and volumes stated on Company Schedule H-2, sheet 16, line 1.

RUCO was unable to duplicate the Company's calculations from the bills and volumes recorded on Schedule H-2, sheet 16; therefore, RUCO issued data request No. 9.01, followed by several telephone conversations in an attempt to obtain the Company's breakdown of the calculation for each customer class's revenue as stated in column (e) on Schedule H-2, sheet 16.

The Company was unable to provide the calculations as to how they reached the test-year revenue using the bill determinants filed on Schedule H-2, sheet 16. Instead the Company's response to RUCO data request No. 9.01 was to provide BFAs for each residential class of service, which were significantly different than the determinants stated on Schedule H-2, sheet 16 and also do not generate the residential test-year margin revenue. To date the Company has been unable to provide a set of test-year billing determinants that generate its test-year recorded revenues.

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Q. Why are accurate test-year billing determinants so important?

A. Accurate test-year billing determinants are essential to the ratemaking process. The test-year billing determinants serve as the starting point to which proforma adjustments are made. The total revenue requirement is then divided over the resulting adjusted billing determinants to determine rates for each service element.

As a result even small inaccuracies in the test-year billing determinants are magnified when utilized to generate an increased level of rates, and can create significant under or over recoveries. An accurate starting point upon which to build is therefore crucial in setting fair and reasonable rates.

Q. What adjustment did you make?

A. RUCO analyzed the BFAs and Schedule H-2, sheet 16 and determined a set of determinants that accurately reflect the size of the test-year customer base, its usage pattern and generate the test-year recorded revenue. These revised determinants provided the basic starting point from which proforma adjustments were added to create a normalized set of test-year determinants to design a rate structure that will produce RUCO's recommended revenue requirement.

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RUCO's revised direct testimony rate design, proof of recommended revenue requirement and typical bill analysis are displayed on attached Revised Schedules RLM-16 and RLM-17.

RATE BASE

Rate Base Adjustment No. 3 – Completed Construction Not Classified

Q. Please explain the Company's Rebuttal position on the proposed adjustment for completed construction not classified ("CCNC").

A. The Company is requesting recovery of those dollars spent in certain non-revenue producing work orders during the test period because those dollars represent rate base that was serving customers during the test year.

Q. Does RUCO agree with the Company's premise on the treatment of CCNC?

A. Yes, RUCO agrees the proper treatment of CCNC is to include all work orders where the plant was placed in-service during the test year.

Q. Why is RUCO then making an adjustment to the Company's CCNC as proposed in SWG's Adjustment No. 20?

A. Through the discovery process, i.e. Staff Data Request JJD-8-9, the Company was specifically requested to provide all appropriate documentation that confirms when the CCNC plant was placed in service.

In response, the Company states: "Please see the attached reports which confirm when the Direct portion of the Company's CCNC, in Adjustment No. 20, was placed into service."

The Company's documentation provided in its response to Staff Data Request JJD-8-9 showed a number of CCNC plant items that were placed in service after the end of the test year. RUCO removed all costs associated with work orders not placed in service during the test year.

Q. Have you revised your position on restating the CCNC pursuant to the Company's rebuttal testimony?

A. No, the Company is inconsistent, by first indicating in its direct testimony that it is appropriate to treat plant as CCNC only when it is confirmed the work order was placed in service at the end of the test year or shortly thereafter; then revising its position to recover expenditures for CCNC work orders placed in service as late as mid-2005, almost a year beyond the end of the test year.

Q. How should the Company treat plant placed in service subsequent to the end of the test period?

A. The Company should have requested these expenditures be considered as Post-Test-Year Plant. Since the Company only requested inclusion of expenditures for work orders placed in service by the end of the test year, RUCO did not perform an analysis as to the appropriateness of considering these expenditures as post test-year plant additions.

However, as a general proposition RUCO does not agree with the inclusion of post test-year plant in rate base. RUCO supports adherence to the historical test-year principle and believes that the introduction of out of test-year plant, with very few exceptions, can skew the ratemaking model by creating mismatches among other ratemaking elements.

Q. Does the Company discuss other elements of RUCO's adjustment to SWG's CCNC Adjustment No. 20?

A. Yes, the Company indicates that RUCO's companion adjustment to remove retirement costs associated with the CCNC work orders is not necessary for SWG's CCNC adjustment due to the negligible impact on rate base.

Q. Do you agree with this assessment?

A. Yes and no. RUCO's methodology removes the entire retirement costs from both the gross plant and the accumulated depreciation; therefore, the impact on the rate base is zero. However, the Company fails to address all aspects of this transaction by ignoring the effects on depreciation expense if retired plant is not removed from rate base. Annual depreciation expenses will remain artificially high if proper ratemaking principles are not adhered to with the removal of all appropriate retirement costs.

Ratepayers would be burdened with inflated depreciation expenses generated from a gross plant in service level, which does not reflect the removal of retired plant, which is no longer used and useful.

Q. In conclusion, what is RUCO's surrebuttal adjustment to SWG's CCNC Adjustment No. 20?

A. As shown in my direct testimony on Schedule RLM-3, page 1, columns (G), (H) and (I), RUCO concludes its original adjustment is fair, reasonable and consistent with the fundamental criteria of CCNC.

Therefore, RUCO did not make any adjustment in its surrebuttal testimony.

OPERATING INCOME

Operating Income Adjustment No. 3 – Labor Annualization

Q. Have you reviewed the Company's rebuttal testimony concerning your adjustment to SWG's income adjustment No. 3 on Labor Annualization?

A. Yes, I have. The Company takes issue with: a) RUCO's disallowance of the post test-year general wage increase and the within-grade movement of its employees for 2005; b) RUCO's calculation of overtime wages; and

c) RUCO's disallowance of the payroll expense related to 37 SWG employees performing sales, marketing and promotional activities.

Q. After analyzing the Company's rebuttal testimony, is RUCO still disallowing the post test-year general wage increase and the within-grade movement of its employees for 2005?

A. Yes. As stated in my direct testimony, RUCO considers the inclusion of the post test-year general wage increase and the within-grade movement of its employees for 2005 has the effect of double counting salary and wage increases. The Company's annualization adjustment served to create a matching between rate base, revenues and expenses to reflect the levels that were in effect at August 31, 2004. Thus, if the post test-year payroll increases are authorized the Company is creating biased rates by being allowed to pick and chose which rate base, expense, and revenue items it will reflect on an actual, projected or annualized basis. The Company's logic that post-test wage increases should be allowed because they are known and measurable could be extended to all other operating income elements, since the Company has recorded data through August 7, 2005; yet SWG did not request post test year treatment of any other rate base, expense, and revenue items. For these reasons RUCO continues to recommend the disallowance of the post test-year wage increases.

. . .

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its calculation of the percentage test-year overtime wages to test-year payroll?

A. Yes, as shown on Schedule SUR-RLM-8, page 3, line 7, I have recalculated the overtime percentage by removing the payroll expense related to 37 SWG employees performing sales, marketing and promotional activities from the test-year recorded regular pay. This revision increases the overtime percentage from 8.53 percent to 8.84 percent for Arizona Direct Labor and from 0.43 percent to 0.44 percent for System Allocable Labor.

Q. After analyzing the Company's rebuttal testimony, is RUCO still eliminating the compensation of 37 SWG employees involved in marketing and sales activities?

A. Yes. RUCO's adjustment is consistent with testimony filed in SWG's recent rate cases and is based on a thorough analysis of the 37 employees responsibilities.

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Q. What is your response to the Company's rebuttal testimony that RUCO relied solely on the information provided in SWG's response to RUCO's data request No. 2.08, i.e. employee compensation received under the Sales Incentive Plan ("SIP")?

A. This claim is not true. RUCO examined this issue in several previous SWG rate cases. In an effort to reduce costs and conserve manpower RUCO relied on the Company's response to RUCO data requests regarding the SIP that were received in two previous rate cases filed in 1996 and 2000.

Q. What specific positions did you recommend be excluded from rates?

A. These positions are as follows: Account Representative, Senior Account Representative, Energy Utilization Engineer, Industrial Gas Engineer, Sales Manager/Supervisor, Manager/Large Customer Sales, and Supervisor/Large Customer Sales.

Q. Are you cognizant of the duties, responsibilities, and job descriptions for these positions?

A. Yes. In reviewing the response to several data requests from previous rate cases the Company has provided complete job descriptions for these positions. The responsibilities of the above-identified positions include the following:

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Account Representative

- Advise customers on gas products and availability.
- Build and maintain relationships with manufacturers, distributors, dealers, and builders.
- Monitor and analyze competitor marketing activities.
- Determine impact of competitive forces in the marketplace.
- Evaluate the effectiveness of promotion and advertising programs.
- Design and implement new marketing programs.

Senior Account Representative

- Implement promotional campaigns.
- Aid dealers and distributors in promotion and selling.
- Schedule advertisement campaigns and/or sales promotions.
- Evaluate market reactions to marketing policies and programs.
- Make presentations to trade allies or prospective customers.

Utilization Engineer

- Advise dealers and distributors of sales and advertising programs.
- Formulate and implement plans for trade association activities.
- Build and maintain relationships with manufacturers, distributors, dealers and builders.
- Keep abreast of industry marketing strategies and tactics.

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Industrial Gas Engineer

- Initiate and develop market opportunities and develop plans to remain competitive.
- Determine market and specific customer requirements and appropriate corporate action.
- Identify opportunities to increase corporate margin for Major Account customers.

Manager/Sales

- Recruit and hire marketing people.
- Establish marketing budgets and goals.
- Train and develop marketing personnel.
- Implement marketing promotion procedures and policies.
- Develop plans for future market positioning.

Supervisor/Sales

- Advise dealers and distributors of sales and advertising programs.
- Schedule the activities of marketing representatives.
- Design and implement new marketing programs.
- Prepare analyses of programs against market requirements and competitor offerings.
- Build and maintain relationships with manufacturers, distributors, dealers, and builders.

Supervisor/Large Customer Programs

- Communicate to management market opportunities and problem areas.
- Initiate and develop market opportunities.
- Conduct market analysis research/evaluation and recommend specific market activities based on analysis.
- Analyze market trends to determine profitable opportunities.
- Determine impact of competitive forces in the marketplace.

Q. Are the duties and responsibilities of these positions the type of activities the Commission has excluded from rates in the past?

A. Yes. The Company has removed over $0.5 million in marketing and promotional costs in this rate application. In its testimony and in response to data requests SWG acknowledges that marketing and promotional activities traditionally have not been included as a component of rates.

Q. Has the Commission always been consistent in disallowing similar costs in prior cases?

A. No. The Company refers to Decision No. 64172 for validation of its position; however, in Decision No. 57075, dated August 31, 1990 the Commission disallowed the following costs:

- Market retention efforts.
- Appliance conversion rebates.

- Advertising the natural gas advantage.
- Encouragement of gas replacements in targeted areas.
- Advocating gas usage in new commercial projects.
- Market research.

Q. What was the Commission's rationale in disallowing these costs?

A. The Commission stated the following in Decision No. 57075 at page 54-55, regarding the rationale for its disallowances:

> Applicant's sales program is, without question, almost entirely motivated by the Company's perception of its competitive position vis-à-vis electric utilities for new and existing customers. This competition between energy providers requires us to evaluate the reasonableness and cost effectiveness of each competitor's marketing and advertising efforts in order to ensure that the ratepayers are not being forced to fund both sides of an escalating competition, without limitation and without realizing any discernible benefits in return.

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Q. What is your response to the Company witness Christina A. Palacios' rebuttal testimony that indicates several of the marketing and sales positions have regulatory responsibilities in addition to essential customer services beneficial to ratepayers?

A. Although the duties, responsibilities and examples provided by Ms. Palacios represent primarily a marketing and sales environment, there are potential scenarios where ratepayers may benefit from these employees' expertise independent of any marketing and sales objectives.

RUCO would be willing to explore revising its position if a fair and reasonable quantification of the time/costs devoted solely to Customer complaint resolution and Regulatory affairs could be substantiated by the Company.

Operating Income Adjustment No. 7 – American Gas Association Dues

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to SWG's income adjustment No. 7 to American Gas Association Dues?

A. No, as explained in my direct testimony, RUCO considers the portion of the American Gas Association ("AGA") Dues dedicated to public affairs and communication to be the responsibilities of the shareholders.

Historically, RUCO has relied on the NARUC annual audit report for a definitive explanation of expenditures and percentages of the AGA dues devoted to each category during the audit year. However, since the NARUC annual audit report is no longer available, RUCO reviewed the Company's response to RUCO data request No.14.2 and specifically the AGA/NARUC Oversight Committee Staff Agreement to determine the AGA's public affairs and communication activities support shareholder interest and encourage greater gas sales. Such activities are primarily for the benefit of shareholders and should not be funded by ratepayers.

Operating Income Adjustment No. 10 – Injuries and Damages Expenses

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to SWG's income adjustment No. 10 to Injuries and Damages Expenses?

A. Yes, RUCO analzyed the Company's rebuttal testimony and determined that a revision was necessary to its recommended 14-year liability for claims between $1 million and $10 million.

Based on the scenario outlined in Incidents #1, #2 and #3 in Company witness, Robert M. Johnson's surrebuttal testimony on page 3, RUCO determined SWG's proforma liability for the 1993 self-insurance claims would be reduced from $18,800,000 to $12,000,000.

This reduction is based on the proforma liability being assessed at $8,800,000 ($1,000,000 from the retention and $7,800,000 from the supplemental retention) for the first incident and $3,200,000 ($1,000,000 from the retention and $2,200,000 from the remaining supplemental retention) for the second incident.

As shown on Schedule SUR-RLM-10, line 4, this adjustment reduces the Company's 14-year liability for claims between $1 million and $10 million proposed liability of $36,247,300 to $29,547,300.

Operating Income Adjustment No. 14 – Miscellaneous Expenses

Q. Has the Company accepted your adjustment to miscellaneous expenses?

A. No, the Company continues to maintain these items are appropriately charged to ratepayers.

Q. Do you continue to support the disallowance of these test-year miscellaneous expenses?

A. Yes. First, my adjustment is consistent with SWG's proposed adjustment No. 3 for miscellaneous expenses. In this adjustment the Company removed $369,364 in miscellaneous expenditures related to meals, gifts, special events, etc. as inappropriate for ratemaking purposes. My review of test-year general ledger sheets merely identifies more of the same. Thus, the Company opposition to my adjustment is contrary to its own adjustment.

. . .

Second, in response to RUCO data request No. 11.01, the Company agreed with the removal of $33,181 of the miscellaneous expenses identified by RUCO.

Despite the Company's agreement with only some of the items identified by RUCO, RUCO maintains certain categories of expenses should not be the financial burden of the ratepayers. For example:

- Liquor, Coffee, Water, Ice, Sodas, Smoothies, Bagels, Donuts, Subs, etc.
- Trophies, Flowers, Gift Certificates, Photographs, etc.
- Charitable/Community/Service Club Donations, Travel Reduction Programs, etc.
- Shareholders Meetings, Recognition Events, Sports Events, Club Memberships, Art Work, etc.
- Barbecues and Accessories, etc.

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to SWG's income adjustment No. 14 to Miscellaneous Expenses?

A. Yes, in an attempt to reduce the number of outstanding issues in the instant rate case, and to avoid the tedious litigation of line-by-line examination of the 40 pages of workpapers, which adequately substantiate the adjustment, RUCO, without further analysis, will make a unilateral reduction of 20% of the direct testimony adjustment from $346,299 to $277,039.

As recorded in my workpapers, RUCO's still supports the position that these test-year expenditures are extravagant, unnecessary for the provisioning of gas service, and/or not the financial responsibility of the ratepayers.

Operating Income Adjustment No. 18 – Property Tax Expense

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to SWG's income adjustment No. 13 to Property Tax?

A. No, the Company agrees with RUCO's adjustment to property taxes.

Operating Income Adjustment No. 21 – Supplemental Executive Retirement Plan

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to SWG's income adjustment No. 14 to the Supplemental Executive Retirement Plan ("SERP")?

A. No, RUCO's position is unchanged – the ratepayers should not be responsible to pay the cost of supplemental benefits to a small select group of high-ranking officers of the Company. However, RUCO did allow the cost of Company's officers' Deferred Compensation Plan ("DCP") to be included in test-year expenses.

The ratepayers are already burdened with the cost of adequately compensating this small select group of high-ranking officers for their work and who are provided with a wide array of benefits including a medical plan, dental plan, life insurance, long term disability, paid absence time, and a retirement plan. If the Company feels it is necessary to provide additional perks to a select group of employees it should do so at its own expense.

These 12 top officers of the Company represent only 0.70% of the Arizona employee base of 1,712; yet, they receive $1,849,069 or 3.85% of the total Arizona employee benefits of $48,004,348.

This demonstrates the excessiveness of the Company's SERP and supports RUCO's recommendation to disallow the cost as a test-year operating expense.

Moreover, a review of the 2004 Annual Meeting of Shareholders and Proxy Statement as provided in the Company's response to RUCO's data request No. 1.06.b illuminates the extent of compensation and benefits the top officers of SWG receive.

It seems disingenuous to request that the ratepayers to be burdened with the cost of this elite retirement plan for a select group of employees who are already receiving lucrative salaries, bonuses, stock awards and options, other unspecified compensation and an employment agreement.

RATE DESIGN

Q. Did you make any surrebuttal adjustment to your rate design?

A. Yes, as shown on Schedule SUR-RLM-16, RUCO's revised direct testimony Schedule RLM-16 provides the correct bill determinants over which the recommended surrebuttal required revenue will be recovered through the adjusted basic service charges and commodity rates.

PROOF OF RECOMMENDED REVENUE

Q. Have you prepared a Schedule presenting proof of your surrebuttal recommended revenue?

A. Yes, I have. Proof that my surrebuttal rate designs will produce the recommended required revenue as illustrated, is presented on Schedule SUR-RLM-16.

TYPICAL BILL ANALYSIS

Q. Have you prepared a Schedule representing the financial impact of your recommended surrebuttal rate design on the typical residential customer?

A. Yes, I have. A typical bill analysis for a residential customer is presented on Schedule SUR-RLM-17.

. . .

CONCLUSION

Q. What changes did RUCO make to its direct filing due to revised calculations recorded in the surrebuttal testimonies?

A. The effect of RUCO witnesses Rodney L. Moore, Marylee Diaz Cortez and William A. Rigsby revised calculations of their direct testimonies are listed below:

	DIRECT TESTIMONY	SURREBUTTAL TESTIMONY
• Percentage Increase In Average Typical Residential Customer's Monthly Statement	4.2%	6.8%
• Recommended Revenue Requirement	$370,818,589	$371,372,057
• Recommended FVRB (Based on50/50 Split Between OCRB & RCND)	$1,163,910,949	$1,164,944,249
• Recommended Required Operating Income	$79,378,637	$79,478,947
• Recommended Percentage Increase In Revenue Requirement	14.85%	15.02%

. . .

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

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SURREBUTTAL
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CORRECTION TO DIRECT TESTIMONY FOR COMPUTATION ERRORS
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	(A) DESCRIPTION	(B) PROPOSED SCHEDULE NO.	(C) BILLING DETERMINANTS NUMBER OF BILLS	(D) BILLING DETERMINANTS SALES (THERMS)	(E) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(F) PROPOSED MARGIN RATES COMMODITY CHARGE	(G) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(H) MARGIN AT PROPOSED RATES COMMODITY CHARGE	(I) TOTAL MARGIN
	Single-Family Residential Gas Service	G-5							
1	Basic Service Charge per Month		8,870,882		$ 10.09		$ 89,520,069		$ 89,520,069
2	Commodity Charge All Therms			261,997,416		0.494191		129,476,751	129,476,751
3	Total Single-Family Residential Gas Service		8,870,882	261,997,416			$ 89,520,069	$ 129,476,751	$ 218,996,820
	Low Income Residential Gas Service	G-5							
4	Basic Service Charge per Month		320,907		10.09		$ 3,238,420		$ 3,238,420
5	Commodity Charge All Therms			9,417,993		0.494191		4,654,287	4,654,287
						0.494191		-	-
6	Total Low Income Residential Gas Service		320,907	9,417,993			$ 3,238,420	$ 4,654,287	$ 7,892,707
	Multi-Family Residential Gas Service	G-6							
7	Basic Service Charge per Month		694,674		8.83		$ 6,133,989		$ 6,133,989
8	Commodity Charge All Therms			14,775,511		0.494191		7,301,924	7,301,924
						0.494191		-	-
9	Total Multi-Family Residential Gas Service		694,674	14,775,511			$ 6,133,989	$ 7,301,924	$ 13,435,912
	Multi-Family Low Income Residential Gas Service	G-6							
10	Basic Service Charge per Month		51,446		8.83		$ 454,269	$ -	$ 454,269.09
11	Commodity Charge All Therms			1,195,957		0.494191		591,031.30	591,031.30
						0.494191		-	-
12	Total Multi-Family Low-Income Gas Service		51,446	1,195,957			$ 454,269	$ 591,031	$ 1,045,300
13	Total Residential Gas Service		9,937,910	287,386,879			99,346,747	142,023,993	241,370,740
	Master Metered Mobile Home Park Gas Service	G-20							
30	Basic Service Charge per Month		2,265		$ 138.62		$ 314,009		$ 314,009
31	Commodity Charge per Therm			2,394,942		0.306328		733,637	733,637
32	Total Master Metered Mobile Home Park Gas Service		2,265	2,394,942			314,009	733,637	1,047,646
	General Gas Service - Small	G-25(S)							
	Basic Service Charge per Month								
1	Former Small Gas Service Customers		197,569		$ 34.66		$ 6,846,834		$ 6,846,834
2	Former Medium Gas Service Customers		96		$ 34.66		3,323		3,323
3	Former Essential Agriculture Customers		144		$ 34.66		4,984		4,984
	Commodity Charge per Therm								
4	Transportation Customers			614		0.655694		403	403
5	Sales Customers			3,697,553		0.655694		2,424,463	2,424,463
6	Total Small General Gas Service		197,809	3,698,167			$ 6,855,141	$ 2,424,865	$ 9,280,006

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	(A) DESCRIPTION	(B) PROPOSED SCHEDULE NO.	(C) BILLING DETERMINANTS NUMBER OF BILLS	(D) BILLING DETERMINANTS SALES (THERMS)	(E) PRESENT MARGIN RATES BASIC SERVICE CHARGE	(F) PRESENT MARGIN RATES COMMODITY CHARGE	(G) MARGIN AT PRESENT RATES BASIC SERVICE CHARGE	(H) MARGIN AT PRESENT RATES COMMODITY CHARGE	(I) TOTAL MARGIN
	General Gas Service - Medium	G-25(M)							
	Basic Service Charge per Month								
7	Former Small Gas Service Customers		191,097		$ 48.52		$ 9,271,558		$ 9,271,558
8	Former Medium Gas Service Customers		3,703		48.52		179,683		179,683
9	Former Large Gas Service Customers		12		48.52		581		581
10	Former Armed Forces Customers		24		48.52		1,163		1,163
11	Former Essential Agriculture Customers		515		48.52		25,004		25,004
	Commodity Charge per Therm								
	Transportation Customers								
12	Former Small Gas Service Customers			99,043		0.380539		37,690	37,690
13	Former Medium Gas Service Customers			83,249		0.380539		31,679	31,679
	Sales Customers			-					
14	Former Small Gas Service Customers			39,993,998		0.380539		15,219,277	15,219,277
15	Former Medium Gas Service Customers			1,704,269		0.380539		648,541	648,541
16	Former Large Gas Service Customers			4,931		0.380539		1,877	1,877
17	Former Armed Forces Customers			3,757		0.380539		1,430	1,430
18	Former Essential Agriculture Customers			130,417		0.380539		49,629	49,629
19	Total Medium General Gas Service		195,352	42,019,665			$ 9,477,990	$ 15,990,121	$ 25,468,111
	General Gas Service - Large	G-25(L)							
	Basic Service Charge per Month								
20	Former Small Gas Service Customers		4,370		$ 207.93		$ 908,591		$ 908,591
21	Former Medium Gas Service Customers		79,287		207.93		16,486,314		16,486,314
22	Former Large Gas Service Customers		120		207.93		24,921		24,921
23	Former Armed Forces Customers		24		207.93		4,984		4,984
	Commodity Charge per Therm								
	Transportation Customers								
24	Former Small Gas Service Customers			79,960		0.260081		20,796	20,796
25	Former Medium Gas Service Customers			2,633,367		0.260081		684,889	684,889
26	Former Large Gas Service Customers			308,963		0.260081		80,356	80,356
	Sales Customers			-					
27	Former Small Gas Service Customers			2,869,954		0.260081		746,421	746,421
28	Former Medium Gas Service Customers			131,577,778		0.260081		34,220,884	34,220,884
29	Former Large Gas Service Customers			1,030,608		0.260081		268,042	268,042
30	Former Armed Forces Customers			164,814		0.260081		42,865	42,865
31	Total Large General Gas Service		83,800	138,665,443			$ 17,424,811	$ 36,064,253	$ 53,489,064
	General Gas Service - Transportation Eligible	G-25(TE)							
	Basic Service Charge per Month								
32	Former Medium Gas Service Customers		60		$ 1,039.66		$ 62,303		$ 62,303
33	Former Essential Agriculture Customers		252		1,039.66		261,674		261,674
34	Former Large Gas Service Customers		1,678		1,039.66		1,744,496		1,744,496
35	Former Armed Forces Customers		60		1,039.66		62,303		62,303
36	Demand Charge Per Month			6,989,384		0.059464		4,967,437	4,967,437
	Commodity Charge per Therm								
	Transportation Customers								
37	Former Medium Gas Service Customers					0.087918		-	-
38	Former Essential Agriculture Customers			4,330,261		0.087918		380,709	380,709
39	Former Large Gas Service Customers			25,225,778		0.087918		2,217,805	2,217,805
	Sales Customers			-					
40	Former Medium Gas Service Customers			992,285		0.087918		87,240	87,240
41	Former Essential Agriculture Customers			4,945,057		0.087918		434,760	434,760
42	Former Large Gas Service Customers			45,369,513		0.087918		3,988,806	3,988,806
43	Former Armed Forces Customers			2,924,591		0.087918		257,125	257,125
44	Total Transportation Eligible General Gas Service		2,049	83,787,486			$ 2,130,777	$ 12,353,881	$ 14,484,658
45	Total General Gas Service		479,010	268,170,761	-	-	$ 35,888,718	$ 66,833,120	$ 102,721,838

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	(A) DESCRIPTION	(B) PROPOSED SCHEDULE NO.	(C) BILLING DETERMINANTS NUMBER OF BILLS	(D) BILLING DETERMINANTS SALES (THERMS)	(E) PRESENT MARGIN RATES BASIC SERVICE CHARGE	(F) PRESENT MARGIN RATES COMMODITY CHARGE	(G) MARGIN AT PRESENT RATES BASIC SERVICE CHARGE	(H) MARGIN AT PRESENT RATES COMMODITY CHARGE	(I) TOTAL MARGIN
	Air Conditioning Gas Service	G-40							
	Basic Service Charge								
1	With Other Service (No Basic Service Charge)		60		$ -		$ -		$ -
2	Basic Service Charge		389		34.66		13,464		13,464
	Commodity Charge per Therm								
3	Transportation Customers			614,147		0.096898		59,510	59,510
4	Sales Customers			1,179,288		0.096898		114,271	114,271
5	Total Air Conditioning Gas Service		448	1,793,435			$ 13,464	$ 173,780	$ 187,245
	Street Lighting Gas Service	G-45							
	Commodity Charge per Therm Of Rated Capacity								
6	All Usage		348	97,538	$ -	$ 0.551118	$ -	$ 53,755	$ 53,755
7	Total Street Lighting Gas Service		348	97,538			$ -	$ 53,755	$ 53,755
	Gas Service For Compression On Customer's Premises	G-55							
	Basic Service Charge								
8	Small		264		$ 34.66	$ -	$ 9,138	$ -	$ 9,138
9	Large		324		485.18		157,005		157,005
10	Residential		1,318		10.09		13,304		13,304
	Commodity Charge per Therm								
11	Transportation Customers					0.12743		-	-
	Sales Customers								
12	Small			178,034		0.12743		22,688	22,688
13	Large			1,854,237		0.12743		236,295	236,295
14	Residential			77,848		0.12743		9,921	9,921
15	*Total Gas Service For Compression On Customer's Premises*		1,906	2,110,119			$ 179,447	$ 268,903	$ 448,350
	Electric Generation Gas Service	G-60							
	Basic Service Charge								
16	General Service - Small		60		$ 34.66		$ 2,077		$ 2,077
17	General Service - Medium				48.52		-		-
18	General Service - Large		84		207.93		17,445		17,445
19	General Service - Transportation Eligible		108		1,039.66		112,146		112,146
20	Essential Agriculture		24		207.93		4,984		4,984
	Commodity Charge per Therm								
21	Transportation Customers			-		0.09671		-	-
22	Sales Customers			14,655,467		0.09671		1,417,303	1,417,303
23	Total Electric Generation Gas Service		276	14,655,467			$ 136,652	$ 1,417,303	$ 1,553,955
	Small Essential Agriculture User Gas Service	G-75							
24	Basic Service Charge		434		$ 207.93		$ 90,340	$ -	$ 90,340
	Commodity Charge per Therm								
25	Transportation Customers			152,234		0.21060		32,060	32,060
26	Sales Customers			2,723,713		0.21060		573,607	573,607
27	Total Small Essential Agriculture Gas Service		434	2,875,947			$ 90,340	$ 605,666	$ 696,006
	Natural Gas Engine Gas Service	G-80							
	Basic Service Charge								
28	Off-Peak Season (October - March)		3,619		$ -	$ -	$ -	$ -	$ -
29	On-Peak Season (April - September)		3,619		138.62		501,562		501,562
	Commodity Charge per Therm								
30	Transportation Customers			-		0.15043		-	-
31	Sales Customers			20,772,070		0.15043		3,124,843	3,124,843
32	Total Natural Gas Engine Gas Service		7,237	20,772,070			$ 501,562	$ 3,124,843	$ 3,626,405
33	Total Tariff Sales		10,429,835	600,257,156			136,470,939	215,234,999	351,705,939
34	Optional Gas Service	G-30	324	101,647,104	$ 1,576.36	0.04951	$ 510,740	$ 5,032,592	$ 5,543,332
35	Special Contract Service	B-1	271	30,410,785	$ 681.56	0.06413	$ 184,703	$ 1,950,134	$ 2,134,837
36	Other Operating Revenues						$ 11,434,480		$ 11,434,480
37	Total Revenue		10,430,430	732,315,046			$ 148,600,862	$ 222,217,725	$ 370,818,588
38	Recommended Annual Revenue Requirement								$ 370,818,589
39	Difference								$ (1)

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CORRECTION TO DIRECT TESTIMONY FOR COMPUTATION ERRORS
TYPICAL BILL ANALYSIS
SINGLE-FAMILY RESIDENTAL GAS SERVICE

COMPARISON OF PRESENT & PROPOSED RATE STRUCTURE

LINE NO.	DESCRIPTION	CONSP'TION (THERMS)	PRESENT SCHEDULES	PROPOSED SCHEDULES	DOLLAR INCREASE	PERCENT INCREASE
			SUMMER			
			May-October Break - 20 Therms	May-October Break - 8 Therms		
	Company					
1	25% Average Usage	3	$ 11.19	$ 19.74	$ 8.55	76.43%
2	75% Average Usage	9	$ 17.57	$ 26.52	$ 8.95	50.97%
3	Average Usage	12	$ 20.76	$ 28.66	$ 7.90	38.06%
4	150% Average Usage	19	$ 27.14	$ 32.93	$ 5.79	21.35%
5	200% Average Usage	25	$ 33.10	$ 37.20	$ 4.10	12.40%
	RUCO					
6	25% Average Usage	3	$ 11.19	$ 13.30	$ 2.11	18.88%
7	75% Average Usage	9	$ 17.57	$ 19.72	$ 2.16	12.27%
8	Average Usage	12	$ 20.76	$ 22.94	$ 2.18	10.48%
9	150% Average Usage	19	$ 27.14	$ 29.36	$ 2.22	8.18%
10	200% Average Usage	25	$ 33.10	$ 35.78	$ 2.68	8.10%
			SWING MONTHS			
			April & November Break - 40 Therms	April & November Break - 8 Therms		
	Company					
11	25% Average Usage	11	$ 19.59	$ 19.74	$ 0.16	0.79%
12	75% Average Usage	34	$ 42.76	$ 26.52	$ (16.23)	-37.97%
13	Average Usage	45	$ 53.90	$ 28.66	$ (25.23)	-46.82%
14	150% Average Usage	68	$ 75.16	$ 32.93	$ (42.23)	-56.18%
15	200% Average Usage	91	$ 96.42	$ 37.20	$ (59.22)	-61.42%
	RUCO					
16	25% Average Usage	11	$ 19.59	$ 21.76	$ 2.17	11.07%
17	75% Average Usage	34	$ 42.76	$ 45.08	$ 2.32	5.43%
18	Average Usage	45	$ 53.90	$ 56.75	$ 2.85	5.29%
19	150% Average Usage	68	$ 75.16	$ 80.07	$ 4.91	6.54%
20	200% Average Usage	91	$ 96.42	$ 103.40	$ 6.98	7.24%
			WINTER			
			December-March Break - 40 Therms	December-March Break - 30 Therms		
	Company					
21	25% Average Usage	11	$ 19.59	$ 29.59	$ 10.01	51.09%
22	75% Average Usage	34	$ 42.76	$ 54.71	$ 11.95	27.95%
23	Average Usage	45	$ 53.90	$ 62.47	$ 8.58	15.91%
24	150% Average Usage	68	$ 75.16	$ 77.99	$ 2.83	3.76%
25	200% Average Usage	91	$ 96.42	$ 93.51	$ (2.92)	-3.03%
	RUCO					
26	25% Average Usage	11	$ 19.59	$ 21.76	$ 2.17	11.07%
27	75% Average Usage	34	$ 42.76	$ 45.08	$ 2.32	5.43%
28	Average Usage	45	$ 53.90	$ 56.75	$ 2.85	5.29%
29	150% Average Usage	68	$ 75.16	$ 80.07	$ 4.91	6.54%
30	200% Average Usage	91	$ 96.42	$ 103.40	$ 6.98	7.24%
	PROPOSED AVERAGE RESIDENTIAL TOTAL ANNUAL GAS SERVICE COSTS					
31	**Company**		$ 447.93	$ 479.17	$ 31.24	6.97%
32	**RUCO**		$ 447.93	$ 478.09	$ 30.16	6.73%
	PRO-RATED AVERAGE RESIDENTIAL MONTHLY GAS SERVICE COSTS (ANNUAL COSTS DIVIDED BY 12 MONTHS)					
33	**Company**		$ 37.33	$ 39.93	$ 2.60	6.97%
34	**RUCO**		$ 37.33	$ 39.84	$ 2.51	6.73%

RATE SCHEDULES

PRESENT BASIC SERVICE

$ 8.00

PRESENT COMMODITY RATE

1.02198
0.9378

BREAKPOINTS

SUMMER (THERMS) (May - Oct)
20

WINTER (THERMS) (May - Oct)
40

PROPOSED RATE DESIGNS

	COMPANY	**RUCO**
BASIC SERVICE	$ 16.00	$ 10.09
COMMODITY RATE *	1.19890 0.68436	1.02879
BREAKPOINTS		
SUMMER (THERMS) (Apr - Nov)	8	N/A
WINTER (THERMS) (Dec - Mar)	30	N/A

* - The Commodity Rate Includes Gas Costs Of $0.5346 Per Therm

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SURREBUTTAL
REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 925,212,447	$ 1,417,642,156	$ 1,171,427,301	$ 919,607,846	$ 1,410,280,651	$ 1,164,944,249
2	Adjusted Operating Income (Loss)	$ 44,233,345	$ 44,233,345	$ 44,233,345	$ 50,211,496	$ 50,211,496	$ 50,211,496
3	Current Rate Of Return (Line 2 / Line 1)	4.78%	3.12%	3.78%	5.46%	3.56%	4.31%
4	Required Operating Income (Line 5 X Line 1)	$ 86,957,942	$ 86,957,942	$ 86,957,942	$ 79,478,947	$ 79,478,947	$ 79,478,947
5	Required Rate Of Return	9.40%	6.13%	7.42%	8.64%	5.64%	6.82%
6	Operating Income Deficiency (Line 4 - Line 2)			$ 42,724,598	$ 29,267,452		$ 29,267,452
7	Gross Revenue Conversion Factor (Schedule RLM-1, Page 2)			1.6573			1.6573
8	Increase In Gross Revenue Requirement (Line 7 X Line 6)			$ 70,809,128			$ 48,506,079
9	Adjusted Test Year Revenue			$ 322,865,978			$ 322,865,978
10	Proposed Annual Revenue Requirement (Line 8 + Line 9)			$ 393,675,106			$ 371,372,057
11	Required Percentage Increase In Revenue (Line 8 / Line 9)			21.93%			15.02%
12	Rate Of Return On Common Equity			11.95%			10.15%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 And D-1
Columns (D) Thru (F): Schedules SUR-RLM-2, SUR-RLM-5, SUR-RLM-6 And RLM-18

Southwest Gas Corporation
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

SURREBUTTAL
RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO OCRB ADJUSTMENTS	REF.	(C) RUCO ADJUSTED AS OCRB
1	Gas Plant In Service	$1,685,504,145	$ (5,313,424)	(1)	$ 1,680,190,721
	Less:				
2	Accumulated Depreciation And Amortization	593,542,006	(1,409,926)	(1)	592,132,080
3	Net Gas Plant In Service (Line 1 - Line 2)	$1,091,962,139	$ (3,903,498)		$ 1,088,058,641
	Additions:				
4	Allowance For Working Capital (MDC-3, Page 1)	$ 881,148	$ (1,924,355)	(2)	$ (1,043,207)
5	Total Additions (Line 4)	$ 881,148	$ (1,924,355)		$ (1,043,207)
	Deductions:				
6	Customer Advances In Aid Of Construction	$ (7,027,372)	$ -		$ (7,027,372)
7	Customer Deposits	(23,912,141)	-		(23,912,141)
8	Deferred Income Taxes	(136,691,328)	223,252	(3)	(136,468,076)
9	Total Deductions (Sum Of Lines 6, 7 & 8)	$ (167,630,841)	$ 223,252		$ (167,407,589)
10	TOTAL ORIGINAL COST RATE BASE (Sum Of Lines 3, 5 & 9)	$ 925,212,447	$ (5,604,601)		$ 919,607,846

References:
Column (A): Company Schedule B-1
Column (B):
(1) Schedule SUR-RLM-3
(2) Schedule MDC-3
(3) Schedule MDC-1
Column (C): Column (A) + Column (B)

Southwest Gas Corporation
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

SURREBUTTAL
"DIRECT" TEST YEAR PLANT SCHEDULES
YEAR ENDED AUGUST 31, 2004

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
				COMPANY TEST YEAR AS FILED		ADJ. NO. 1	ADJ. NO. 2		RUCO ADJUSTMENT NO. 3			RUCO ADJUSTMENT NO. 4			RUCO AS ADJUSTED		
LINE NO.	ACCT NO.	ACCOUNT NAME	DEP RATE	TOTAL PLANT VALUE	ACCUMULATED DEPRECIATION	RUCO DR 7.01(C) ACC. DEP	PIPE SUR'Y/REP'R	PIPE SUR/REP ACC. DEP	CCNC NET ADDITIONS	ACC DEP CCNC ADDITIONS	ACC DEP CCNC RETIREMENTS	MISC INT'GIBLE NET PLANT	ACC. DEP INT'G ADDITIONS	ACC. DEP INT'G RETIREMENTS	TOTAL PLANT VALUE	ACCUMULATED DEPRECIATION	NET PLANT VALUE
		Intangible Plant:															
1	301.0	Organization	Amor'd	$ 42,653	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,653	$ -	$ 42,653
2	302.0	Franchises & Consents	Amor'd	1,714,402	529,246	-	-	-	-	-	-	-	-	-	1,714,402	529,246	1,185,156
3	303.0	Miscellaneous Intangible	Amor'd	1,945,631	1,667,452	-	-	-	-	-	-	-	-	-	1,945,631	1,667,452	278,179
4		Total Intangible Plant		$ 3,702,686	$ 2,196,698	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,702,686	$ 2,196,698	$ 1,505,988
		Distribution Plant:															
5	374.1	Land & Land Rights	N/A	$ 351,685	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 351,685	$ -	$ 351,685
6	374.2	Rights Of Way	2.15%	720,979	274,994	-	-	-	-	-	-	-	-	-	720,979	274,994	445,985
7	375.0	Structures	1.15%	110,557	62,874	3,923	-	-	-	-	-	-	-	-	110,557	66,797	43,760
8	376.0	Mains	3.82%	789,647,065	273,373,290	-	(1,224,119)	(72,387)	(1,465,395)	6,390	40,038	-	-	-	786,937,551	273,267,255	513,670,296
9	378.0	Measuring & Regulating Station	4.12%	24,454,990	1,274,807	-	-	-	-	-	-	-	-	-	24,454,990	1,274,807	23,180,183
10	380.0	Services	5.30%	523,802,714	218,592,143	-	(1,115,660)	(61,455)	-	-	-	-	-	-	522,687,054	218,530,688	304,156,366
11	381.0	Meters	1.98%	156,809,964	30,981,761	-	-	-	-	-	-	-	-	-	156,809,964	30,981,761	125,828,203
12	385.0	Industrial Measuring & Reg. Station	4.31%	6,528,499	2,586,375	-	-	-	-	-	-	-	-	-	6,528,499	2,586,375	3,942,124
13	387.0	Other Equipment	5.26%	462,730	502,185	14,288	-	-	-	-	-	-	-	-	462,730	516,473	(53,743)
14		Total Distribution Plant		$ 1,502,889,183	$ 527,648,429	$ 18,211	$ (2,339,779)	$ (133,842)	$ (1,465,395)	$ 6,390	$ 40,038	$ -	$ -	$ -	$ 1,499,064,009	$ 527,499,150	$ 971,564,859
		General Plant:															
15	389.0	Land & Land Rights	N/A	$ 6,454,589	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,454,589	$ -	$ 6,454,589
16	390.1	Structures	1.84%	26,285,123	7,274,350	-	-	-	-	-	-	-	-	-	26,285,123	7,274,350	19,010,773
17	390.2	Structures - Leasehold Improv'ts	Amor'd	1,005,567	599,767	37,893	-	-	-	-	-	-	-	-	1,005,567	637,660	367,917
18	391.0	Office Furniture And Equipment	2.73%	4,849,827	656,607	-	-	-	-	-	-	-	-	-	4,849,827	656,607	4,193,220
19	391.1	Computer Equipment	14.87%	8,489,038	1,178,796	-	-	-	-	-	-	-	-	-	8,489,038	1,178,796	7,310,242
20	392.1	Transportation Equipment	7.65%	30,447,147	5,293,542	-	-	-	-	-	-	-	-	-	30,447,147	5,293,542	25,153,605
21	393.0	Stores Equipment	2.08%	481,909	14,058	-	-	-	-	-	-	-	-	-	481,909	14,058	467,851
22	394.0	Tools, Shop And Garage Equip	2.17%	4,891,998	(2,642,962)	-	-	-	-	-	-	-	-	-	4,891,998	(2,642,962)	7,534,960
23	395.0	Laboratory Equipment	3.93%	425,322	(150,109)	-	-	-	-	-	-	-	-	-	425,322	(150,109)	575,431
24	396.0	Power Operated Equipment	3.88%	3,807,547	1,118,830	-	-	-	-	-	-	-	-	-	3,807,547	1,118,830	2,688,717
25	397.0	Communication Equipment	8.88%	2,223,684	2,332,366	-	-	-	-	-	-	-	-	-	2,223,684	2,332,366	(108,682)
26	397.2	Telemetering Equipment	6.19%	560,307	432,184	-	-	-	-	-	-	-	-	-	560,307	432,184	128,123
27	398.0	Miscellaneous Equipment	4.53%	844,186	32,818	78	-	-	-	-	-	-	-	-	844,186	32,896	811,290
28		Total General Plant		$ 90,766,244	$ 16,140,237	$ 37,971	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,766,244	$ 16,178,208	$ 74,588,036
29		TOTAL DIRECT PLANT		$ 1,597,358,113	$ 545,985,364	$ 56,182	$ (2,339,779)	$ (133,842)	$ (1,465,395)	$ 6,390	$ 40,038	$ -	$ -	$ -	$ 1,593,532,939	$ 545,874,056	$ 1,047,658,883
30		Alloc'd Plant (See SUR-RLM-3, Page 2, Line 31)		88,146,035	47,556,640	-	-		(116,232)	(12,297)	-	(1,372,021)	(228,670)	1,057,650	86,657,782	46,258,024	40,399,758
31		TOTAL PLANT		$ 1,685,504,148	$ 593,542,004	$ 56,182	$ (2,339,779)	$ (133,842)	$ (1,601,627)	$ (5,907)	$ 40,038	$ (1,372,021)	$ (228,670)	$ 1,057,650	$ 1,680,190,721	$ 592,132,080	$ 1,088,058,641
32		Direct Plant As Per Company		$ 1,597,358,113	$ 545,985,364	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,597,358,113	$ 545,985,364	1,051,372,749
		Common Plant As Per Company		88,146,035	47,556,640	-	-	-	-	-	-	-	-	-	88,146,035	$ 47,556,640	40,589,394
33		Difference		$ -	$ -	$ 56,182	$ (2,339,779)	$ (133,842)	$ (1,601,627)	$ (5,907)	$ 40,038	$ (1,372,021)	$ (228,670)	$ 1,057,650	$ (5,313,427)	$ (1,409,924)	$ (3,903,502)

References
Columns (A) (B) (C): Company Workpapers B-2, Sheets 1 Through 8 And C-2, Adjustment 17, Sheets 1 Through 5
Column (D): Company Response To RUCO Data Request 7.01(C)
Columns (E) (F): See Testimony, MDC
Columns (G) (H) (I): See Schedule RLM-4, Pages 1 & 2
Columns (J) (K) (L): See Testimony, MDC
Column (M): Sum Of Cols. (B) (E) (G) (J)
Column (N): Sum Of Cols. (C) (D) (F) (H) (K) - Minus Cols. (I) (L)
Column (O): Column (M) - Column (N)

Southwest Gas Corporation
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule SUR-RLM-3
Page 2 of 2

SURREBUTTAL
"SYSTEM ALLOCABLE" TEST YEAR PLANT SCHEDULES
YEAR ENDED AUGUST 31, 2004

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
				COMPANY TEST YEAR AS FILED		ADJ. NO. 1	ADJ. NO. 2		RUCO ADJUSTMENT NO. 3			RUCO ADJUSTMENT NO. 4			RUCO AS ADJUSTED		
LINE NO.	ACCT NO.	ACCOUNT NAME	DEP RATE	TOTAL PLANT VALUE	ACCUMULATED DEPRECIATION	RUCO DR 7.01(C) ACC. DEP	PIPE SURV/REPR	PIPE SURV/REP ACC. DEP	CONC NET ADDITIONS	ACC DEP CONC ADDITIONS	ACC DEP CONC RETIREMENTS	MISC INT'GIBLE NET PLANT	ACC. DEP INT'G ADDITIONS	ACC. DEP INT'G RETIREMENTS	TOTAL PLANT VALUE	ACCUMULATED DEPRECIATION	NET PLANT VALUE
		Intangible Plant:															
1	301.0	Organization	0.00%	$ 61,816	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,816	$ -	$ 61,816
2	302.0	Franchises & Consents	Amor'd	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	303.0	Miscellaneous Intangible	Amor'd	106,174,215	60,385,073	-	-	-	-	-	-	(2,382,819)	(397,136)	1,836,844	103,791,396	58,151,094	45,640,303
4		Total Intangible Plant		$ 106,236,031	$ 60,385,073	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,382,819)	$ (397,136)	$ 1,836,844	$ 103,853,212	$ 58,151,094	$ 45,702,119
		Distribution Plant:															
5	374.1	Land & Land Rights	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	374.2	Rights Of Way	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	375.0	Structures	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	376.0	Mains	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	378.0	Measuring & Regulating Station	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	380.0	Services	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	381.0	Meters	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	385.0	Industrial Measuring & Reg. Station	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	387.0	Other Equipment	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14		Total Distribution Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		General Plant:															
15	389.0	Land & Land Rights	0.00%	$ 391,307	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 391,307	$ -	$ 391,307
16	390.1	Structures	2.46%	11,831,108	3,565,211	-	-	-	-	-	-	-	-	-	11,831,108	3,565,211	8,265,897
17	390.2	Structures - Leasehold Improv'ts	Amor'd	3,144,329	2,895,028	-	-	-	-	-	-	-	-	-	3,144,329	2,895,028	249,301
18	391.0	Office Furniture And Equipment	3.99%	7,755,795	1,861,177	-	-	-	(4,145)	(83)	-	-	-	-	7,751,650	1,861,094	5,890,556
19	391.1	Computer Equipment	30.01%	13,573,926	10,549,263	-	-	-	(128,028)	(19,211)	-	-	-	-	13,445,898	10,530,052	2,915,846
20	392.1	Trans. Equip. - Light Vehicles	6.42%	3,389,404	1,095,677	-	-	-	(50,507)	(1,621)	-	-	-	-	3,338,897	1,094,056	2,244,841
21	393.0	Trans. Equip. - Heavy Vehicles	6.42%	111,293	(34,504)	-	-	-	-	-	-	-	-	-	111,293	(34,504)	145,797
22	394.0	Stores Equipment	4.45%	24,106	(5,005)	-	-	-	(16,720)	(372)	-	-	-	-	7,386	(5,377)	12,763
23	395.0	Tools, Shop And Garage Equip.	4.10%	414,693	(29,696)	-	-	-	-	-	-	-	-	-	414,693	(29,696)	444,389
24	396.0	Laboratory Equipment	3.05%	268,894	82,474	-	-	-	-	-	-	-	-	-	268,894	82,474	186,420
25	397.0	Communication Equipment	9.88%	4,605,689	2,519,905	-	-	-	-	-	-	-	-	-	4,605,689	2,519,905	2,085,784
26	397.2	Telemetering Equipment	20.38%	401,430	(186,565)	-	-	-	-	-	-	-	-	-	401,430	(186,565)	587,995
27	398.0	Miscellaneous Equipment	5.65%	937,148	(105,377)	-	-	-	(2,462)	(70)	-	-	-	-	934,686	(105,447)	1,040,133
28		Total General Plant		$ 46,849,122	$ 22,207,588	$ -	$ -	$ -	$ (201,862)	$ (21,356)	$ -	$ -	$ -	$ -	$ 46,647,260	$ 22,186,232	$ 24,461,028
29		TOTAL ALLOCABLE PLANT		$ 153,085,153	$ 82,592,661	$ -	$ -	$ -	$ (201,862)	$ (21,356)	$ -	$ (2,382,819)	$ (397,136)	$ 1,836,844	$ 150,500,472	$ 80,337,325	$ 70,163,147
30		Allocation Factor		57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%
31		TOTAL ALLOCATE PLANT		$ 88,146,035	$ 47,556,640	$ -	$ -	$ -	$ (116,232)	$ (12,297)	$ -	$ (1,372,021)	$ (228,670)	$ 1,057,650	$ 86,657,782	$ 46,258,024	$ 40,399,758

References:
Columns (A) (B) (C): Company Workpapers B-2, Sheets 1 Through 8 And C-2, Adjustment 17, Sheets 1 Through 5
Column (D): Company Response To RUCO Data Request 7.01(C)
Columns (E) (F): See Testimony, MDC
Columns (G) (H) (I): See Schedule RLM-4, Pages 1 & 2
Columns (J) (K) (L): See Testimony, MDC
Column (M): Sum Of Cols. (B) (E) (G) (J)
Column (N): Sum Of Cols. (C) (D) (F) (H) (K) - Minus Cols. (I) (L)
Column (O): Column (M) - Column (N)

Southwest Gas Corporation
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

SURREBUTTAL
RATE BASE - RECONSTRUCTED COST NEW DEPRECIATED

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS RCND	(B) RUCO RCND ADJUSTMENTS	(C) RUCO ADJUSTED AS RCND
1	Gas Plant In Service	$ 2,441,205,028	$ (7,695,714)	$ 2,433,509,314
	Less:			
2	Accumulated Depreciation And Amortization	856,813,179	(2,035,312)	854,777,867
3	Net Gas Plant In Service (Line 1 - Line 2)	$ 1,584,391,849	$ (5,660,401)	$ 1,578,731,448
	Additions:			
4	Allowance For Working Capital	$ 881,148	$ (1,924,355)	$ (1,043,207)
5	Total Additions (Line 4)	$ 881,148	$ (1,924,355)	$ (1,043,207)
	Deductions:			
6	Customer Advances In Aid Of Construction	$ (7,027,372)	$ -	$ (7,027,372)
7	Customer Deposits	(23,912,141)	-	(23,912,141)
8	Deferred Income Taxes	(136,691,328)	223,252	(136,468,076)
9	Total Deductions (Sum Lines 6, 7 & 8)	$ (167,630,841)	$ 223,252	$ (167,407,589)
10	TOTAL RCND RATE BASE	$ 1,417,642,156	$ (7,361,505)	$ 1,410,280,651

References:
Column (A): Company Schedule B-1
Column (B): Column (C) - Column (A)
Column (C): OCRB (SUR-RLM-2, Column (C)) X Same Ratio As The Company's RCND Is To Its OCRB (144.84%)

Southwest Gas Corporation
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

SURREBUTTAL
OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJTMENTS	(C) RUCO TEST YEAR AS ADJUSTED	(D) RUCO PROPOSED CHANGES	(E) RUCO AS RECOMMENDED
1	Revenues	$ 322,865,978	$ -	$ 322,865,978	$ 48,506,079	$ 371,372,057
2	Gas Cost	-	-	-	-	-
3	TOTAL MARGIN	$ 322,865,978	$ -	$ 322,865,978	$ 48,506,079	$ 371,372,057
	EXPENSES:					
4	Other Gas Supply	$ 740,391	$ (21,030)	$ 719,361	$ -	$ 719,361
5	Distribution	78,580,466	(4,743,687)	73,836,779	-	73,836,779
6	Customer Accounts	34,003,279	(1,498,542)	32,504,737	-	32,504,737
7	Customer Information	548,496	(16,817)	531,679	-	531,679
8	Sales	-	-	-	-	-
	Administration & General					
9	Direct	6,993,300	(83,716)	6,909,584	-	6,909,584
10	System Allocable	45,487,895	(3,601,085)	41,886,810	-	41,886,810
	Depreciation & Amortization					
11	Direct	67,338,861	(109,637)	67,229,224	-	67,229,224
12	System Allocable	7,062,583	(123,789)	6,938,794	-	6,938,794
13	Regulatory Amortizations	1,548,204	(1,044,968)	503,236	-	503,236
14	Other Taxes	33,455,124	(1,267,863)	32,187,261	-	32,187,261
15	Interest On Cust. Deposits	717,364	-	717,364	-	717,364
16	Income Taxes	2,156,664	6,532,990	8,689,654	19,238,627	27,928,281
17	TOTAL EXPENSES	$ 278,632,626	$ (5,978,145)	$ 272,654,482	$ 19,238,627	$ 291,893,110
18	NET INCOME (LOSS)	$ 44,233,351		$ 50,211,496		$ 79,478,947

References:
Column (A): Company Schedule C-1
Column (B): Testimony, SUR-RLM And Schedule SUR-RLM-7
Column (C): Column (A) + Column (B)
Column (D): Testimony, SUR-RLM And Schedule SUR-RLM-1, Pages 1 & 2
Column (E): Column (C) + Column (D)

Southwest Gas Corporation
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) LEFT BLANK	(C) ADJ #3	(D) LEFT BLANK	(E) ADJ #7	(F) ADJ #8	(G) ADJ #10	(H) ADJ #12	(I) ADJ #14
1	Revenues	$322,865,978	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Gas Cost	-	-	-	-	-	-	-	-	-
3	TOTAL MARGIN	$322,865,978	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	EXPENSES:									
4	Other Gas Supply	$ 740,391	$ -	$ (11,215)	$ -	$ -	$ -	$ -	$ -	$ -
5	Distribution	78,580,466	-	(2,369,054)	-	-	-	-	(1,488,287)	(150,532)
6	Customer Accounts	34,003,279	-	(1,109,601)	-	-	-	-	-	(8,572)
7	Customer Information	548,496	-	(12,878)	-	-	-	-	-	-
8	Sales	-	-	-	-	-	-	-	-	-
	Administration & General									
9	Direct	6,993,300	-	(31,713)	-	-	-	-	-	-
10	System Allocable	45,487,895	-	(700,264)	-	(75,385)	240,016	-		(117,935)
	Depreciation & Amortization									
11	Direct	67,338,861	-	-	-	-	-	-	-	-
12	System Allocable	7,062,583	-	-	-	-	(12,932)	-	-	-
13	Regulatory Amortizations	1,548,204	-	-	-	-	-	-	(1,044,968)	-
14	Other Taxes	33,455,124	-	-	-	-	-	-	-	-
15	Interest On Cust. Deposits	717,364	-	-	-	-	-	-	-	-
16	Income Taxes	2,156,664	-	-	-	-	-	-	-	-
17	TOTAL EXPENSES	$278,632,627	$ -	$ (4,234,725)	$ -	$ (75,385)	$ 227,084	$ -	$ (2,533,255)	$ (277,039)
18	NET INCOME (LOSS)	$ 44,233,351								

Adjustment No.:	References:
1 - Left Blank	
3 - Labor And Labor Loading Annualization	Testimony, SUR-RLM And Schedule SUR-RLM-8, Pages 1 To 7
4 - Left Blank	
7 - Amercian Gas Association ("AGA") Dues	Testimony, SUR-RLM And Schedule RLM-9, Page 1
8 - Sarbanas-Oxley Section 404 Compliance	Testimony, MDC And Schedule MDC-4
10 - Injuries And Damages	Testimony, SUR-RLM And Schedule SUR-RLM-10, Page 1
12 - Transmission Integrity Management Program	Testimony, MDC And Schedule MDC-5
14 - Miscellaneous Adjustments	Testimony, SUR-RLM And Schedule SUR-RLM-11, Page 1

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENTS - CONT'D
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(J) ADJ #17	(K) ADJ #18	(L) ADJ #20	(M) ADJ #21	(N) LEFT BLANK	(O) LEFT BLANK	(P) LEFT BLANK	(Q) INCOME TAX	(R) RUCO AS AD'TED
1	Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$322,865,978
2	Gas Cost	-	-	-	-	-	-	-	-	-
3	TOTAL MARGIN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$322,865,978
	EXPENSES:									
4	Other Gas Supply	$ -	$ -	$ -	$ (9,815)	$ -	$ -	$ -	$ -	$ 719,361
5	Distribution	-	-	-	(735,813)	-	-	-	-	73,836,779
6	Customer Accounts	-	-	-	(380,369)	-	-	-	-	32,504,737
7	Customer Information	-	-	-	(3,939)	-	-	-	-	531,679
8	Sales	-	-	-	-	-	-	-	-	-
	Administration & General									
9	Direct	-	-	-	(52,003)	-	-	-	-	6,909,584
10	System Allocable	-	-	(2,563,384)	(384,133)	-	-	-	-	41,886,810
	Depreciation & Amortization									
11	Direct	(109,637)	-	-	-	-	-	-	-	67,229,224
12	System Allocable	(110,857)	-	-	-	-	-	-	-	6,938,794
13	Regulatory Amortizations	-	-	-	-	-	-	-	-	503,236
14	Other Taxes	-	(1,267,863)	-	-	-	-	-	-	32,187,261
15	Interest On Cust. Deposits	-	-	-	-	-	-	-	-	717,364
16	Income Taxes	-	-	-	-	-	-	-	6,532,990	8,689,654
17	TOTAL EXPENSES	$ (220,495)	$ (1,267,863)	$ (2,563,384)	$ (1,566,073)	$ -	$ -	$ -	$ 6,532,990	$272,654,482
18	NET INCOME (LOSS)									$ 50,211,496

Adjustment No.:	References:
17 - Deprecitation/Amortization Expense	Testimony, SUR-RLM, Schedule SUR-RLM-12, Pages 1 & 2 and Schedule MDC-6
18 - Property Tax Expense	Testimony, SUR-RLM And Schedule SUR-RLM-13, Page 1
20 - RUCO Adjustment To Management Incentive Plan	Testimony, MDC
21 - RUCO Adjustment To SERP	Testimony, SUR-RLM And Schedule SUR-RLM-14, Page 1
22 - Left Blank	
23 - Left Blank	
24 - Left Blank	
25 - RUCO Adjustment To Income Tax	Testimony, SUR-RLM And Schedule SUR-RLM-15, Page 1

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SURREBUTTAL
EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3
LABOR AND LABOR LOADING ADJUSTMENT

LINE NO.	ARIZONA ACOUNT NUMBERS	(A) RUCO AS ADJUSTED LABOR (See SUR-RLM-8, Pg 2, C (I)	(B) LOADING (See SUR-RLM-8, Pg 2, C (J)	(C) TOTAL (Sum Of Columns (A) And (B)
	OPERATIONS			
1	813	$ 455,832	$ 216,139	$ 671,971
2	851	-	-	-
3	870	4,516,420	2,471,039	6,987,459
4	871	353,388	168,757	522,145
5	874	3,217,553	1,766,426	4,983,979
6	875	1,209,398	663,124	1,872,523
7	878	3,566,758	1,959,621	5,526,379
8	879	4,213,776	2,317,540	6,531,316
9	880	3,877,730	2,123,083	6,000,813
10	901	2,198,381	1,209,529	3,407,910
11	902	3,157,967	1,733,369	4,891,336
12	903	11,034,154	5,837,771	16,871,925
13	905	229,577	125,905	355,482
14	908	169,525	93,067	262,592
15	909	-	-	-
16	910	483	254	737
17	920	29,532,070	14,035,006	43,567,076
18	922	-	-	-
19	930	29,401	13,956	43,357
20	SUBTOTAL	$ 67,762,413	$ 34,734,587	$ 102,497,000
	MAINTENANCE			
21	885	$ 1,465,754	$ 802,645	$ 2,268,399
22	886	8,440	4,600	13,040
23	887	4,619,107	2,534,716	7,153,823
24	889	688,285	377,723	1,066,008
25	892	3,272,194	1,797,488	5,069,682
26	893	693,998	380,139	1,074,137
27	894	92,633	50,672	143,305
28	CORPORATE DIRECT 935	418,703	229,599	648,302
	SYSTEM ALLOCABLE 935	181,976	86,926	268,902
29	SUBTOTAL	$ 11,259,114	$ 6,177,582	$ 17,705,598
30	TOTALS	$ 79,021,527	$ 40,912,169	$ 120,202,598

LINE NO.	FUNCTIONALIZATION	COMPANY AS FILED (WP, ADJ. 3, Pg 11 Thru 24)	RUCO AS ADJUSTED (From Col. (C), Lines 1 To 29)	ADJUSTMENT (Col. (B) - (A)) (See SUR-RLM-7, Pg 1, C (C))
31	OTHER GAS SUPPLY (813)	$ 683,186	$ 671,971	$ (11,215)
32	DISTRIBUTION (870-880 & 885-894)	51,582,063	49,213,009	(2,369,054)
33	CUST. ACC'TS (901, 902, 903 & 905)	26,636,254	25,526,653	(1,109,601)
34	CUST. SER. & INFO (908, 909, & 910)	276,206	263,328	(12,878)
35	SALES			
	ADMINISTRATION & GENERAL			
36	CORPORATE DIRECT (935)	680,015	648,302	(31,713)
37	SYS. ALLOC. (920, 922, 930 & 935)	44,579,599	43,879,335	(700,264)
38	TOTAL	$ 124,437,323	$ 120,202,598	$ (4,234,725)
39	RUCO ADJUSTMENT TO LABOR AND LABOR LOADING (See SUR-RLM-7, Page 1, Col (C), Line17)			$ (4,234,725)

References:
Columns (A) (B) (C): Calculated From The Following 6 Pages Of Schedule SUR-RLM-8

SURREBUTTAL
EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANNUALIZED LABOR AND LOADING PER RUCO ADJUSTMENTS

LINE	ACCT	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
		ARIZONA		CORPORATE DIRECT		TOTAL DIRECT		SYSTEM ALLOCATED		TOTAL ANNUALIZATION	
		LABOR	LOADING	LABOR	LOADING	LABOR	LOADING	LABOR	LOADING	LABOR	LOADING
NO.	NO.	SUR-8, P5, (C)	SUR-8, P6, (C)	SUR-8, P5, (F)	SUR-8, P6, (F)	Col. (A) + (C)	Col. (B) + (D)	SUR-8, P5, (I)	SUR-8, P6, (I)	Col. (E) + (G)	Col. (F) + (H)
	OPERATIONS										
1	813	$ -	$ -	$ 455,832	$ 216,139	$ 455,832	$ 216,139	$ -	$ -	$ 455,832	$ 216,139
2	851	-	-	-	-	-	-	-	-	-	-
3	870	4,216,473	2,311,393	299,947	159,646	4,516,420	2,471,039	-	-	4,516,420	2,471,039
4	871	11,556	6,273	341,832	162,484	353,388	168,757	-	-	353,388	168,757
5	874	3,217,553	1,766,426	-	-	3,217,553	1,766,426	-	-	3,217,553	1,766,426
6	875	1,209,398	663,124	-	-	1,209,398	663,124	-	-	1,209,398	663,124
7	878	3,566,758	1,959,621	-	-	3,566,758	1,959,621	-	-	3,566,758	1,959,621
8	879	4,213,776	2,317,540	-	-	4,213,776	2,317,540	-	-	4,213,776	2,317,540
9	880	3,849,883	2,110,325	27,847	12,758	3,877,730	2,123,083	-	-	3,877,730	2,123,083
10	901	2,198,381	1,209,529	-	-	2,198,381	1,209,529	-	-	2,198,381	1,209,529
11	902	3,157,967	1,733,369	-	-	3,157,967	1,733,369	-	-	3,157,967	1,733,369
12	903	8,146,838	4,468,440	1,335,013	631,290	9,481,851	5,099,731	1,552,303	738,040	11,034,154	5,837,771
13	905	229,577	125,905	-	-	229,577	125,905	-	-	229,577	125,905
14	908	169,525	93,067	-	-	169,525	93,067	-	-	169,525	93,067
15	909	-	-	-	-	-	-	-	-	-	-
16	910	483	254	-	-	483	254	-	-	483	254
17	920	-	-	-	-	-	-	29,532,070	14,035,006	29,532,070	14,035,006
18	922	-	-	-	-	-	-	-	-	-	-
19	930	-	-	-	-	-	-	29,401	13,956	29,401	13,956
20	SUBTOT	$ 34,188,169	$ 18,765,267	$ 2,460,470	$ 1,182,317	$ 36,648,639	$ 19,947,584	$ 31,113,774	$ 14,787,003	$ 67,762,413	$ 34,734,587
	MAINTENANCE										
21	885	$ 1,364,407	$ 748,934	$ 101,347	$ 53,711	$ 1,465,754	$ 802,645	$ -	$ -	$ 1,465,754	$ 802,645
22	886	8,440	4,600	-	-	8,440	4,600	-	-	8,440	4,600
23	887	4,619,107	2,534,716	-	-	4,619,107	2,534,716	-	-	4,619,107	2,534,716
24	889	688,285	377,723	-	-	688,285	377,723	-	-	688,285	377,723
25	892	3,272,194	1,797,488	-	-	3,272,194	1,797,488	-	-	3,272,194	1,797,488
26	893	693,998	380,139	-	-	693,998	380,139	-	-	693,998	380,139
27	894	92,633	50,672	-	-	92,633	50,672	-	-	92,633	50,672
28	935	418,703	229,599	-	-	418,703	229,599	181,976	86,926	600,679	316,525
29	SUBTOT	$ 11,157,768	$ 6,123,871	$ 101,347	$ 53,711	$ 11,259,114	$ 6,177,582	$ 181,976	$ 86,926	$ 11,441,091	$ 6,264,507
30	O & M	$ 45,345,937	$ 24,889,138	$ 2,561,817	$ 1,236,028	$ 47,907,753	$ 26,125,166	$ 31,295,750	$ 14,873,929	$ 79,203,503	$ 40,999,095

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SURREBUTTAL
EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANNUALIZED LABOR

LINE NO.	DESCRIPTION	(A) ARIZONA DIRECT	(B) CORPORATE DIRECT	(C) SYSTEM ALLOCABLE	(D) TOTAL
1	ANNUALIZED SALARY (WP C-2, ADJ. 3, SH 3)	$ 61,779,296	$ 2,843,265	$ 36,475,304	
	LESS:				
2	SALES/MARK'G DISALLOW (SUR-RLM-8, Pg 7)	(2,125,266)	-	(767,168)	
3	SUBTOTAL (Line 1 + Line 2)	$ 59,654,030	$ 2,843,265	$ 35,708,136	
	PLUS:				
4	2005 WAGES INCREASE % (Testimony, RLM)	0.00%	0.00%	0.00%	
5	2005 WAGE INCREASE (Line 3 X Line 4)	$ -	$ -	$ -	
6	SUBTOTAL (Line 3 + Line 5)	$ 59,654,030	$ 2,843,265	$ 35,708,136	
7	OVERTIME % (See Line 24)	8.84%	2.77%	0.44%	
8	OVERTIME (Line 6 X Line 7)	$ 5,270,795	$ 78,790	$ 157,459	
9	TOTAL ANNUALIZED PAYROLL (Line 1 + Line 8)	$ 64,924,825	$ 2,922,055	$ 36,632,763	
	LESS:				
10	PERCENT INDIRECT TIME (WP C-2, ADJ. 3, SH 4)	13.53%	12.33%	12.33%	
11	INDIRECT TIME (Line 9 X Line 10)	$ 8,787,421	$ 360,238	$ 4,516,177	
12	NET ANNUALIZED LABOR (Line 9 + Line 11)	$ 56,137,403	$ 2,561,817	$ 32,116,586	
13	O & M RATIO (WP C-2, ADJ. 3, SH 2)	81.02%	100.00%	96.51%	
14	O & M SUBTOTAL (Line 12 X Line 13)	$ 45,480,959	$ 2,561,817	$ 30,996,513	
15	ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 15)	100.00%	100.00%	57.58%	
16	O & M SUBTOTAL ALLOCABLE (Line 14 X Line 15)	$ 45,480,959	$ 2,561,817	$ 17,847,792	
17	NET OF PAIUTE (SEE NOTE A)	$ -	$ -	$ (704,227)	
18	O & M TOTAL ALLOCABLE (Line 16 + Line 17)	$ 45,480,959	$ 2,561,817	$ 17,143,565	
19	COMPANY AS FILED (WP C-2, ADJ. 3, SH 15 & 20)	$ 48,681,264	$ 2,620,441	$ 17,553,678	
20	RUCO ADJUSTMENT (Line 18 - Line 19)	$ (3,200,305)	$ (58,624)	$ (410,113)	$ (3,669,043)
21	ANNUALIZED EMPLOYEES (WP C-2, ADJ. 3, SH 3)	1,171	39	502	1,712
	REVISED OVERTIME CALCULATION				
22	TEST-YEAR RECORDED OVERTIME	$ 5,308,604	$ 56,936	$ 159,104	
23	REGULAR PAY MINUS SALES DISALLOWANCE	60,081,948	2,054,630	36,081,280	
24	OVERTIME PERCENTAGE	8.84%	2.77%	0.44%	

NOTE (A)

LINE NO.	DESCRIPTION	AMOUNT
25	PAIUTE ADJUSTMENT	
26	RUCO ADJUSTED 920	$ 29,532,070
27	RUCO ADJUSTED 930	29,401
28	RUCO ADJUSTED 935	181,976
29	SUBTOTAL (Sum Of Lines 23, 24 & 25)	$ 29,743,447
30	PAIUTE ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 19)	-4.29%
31	NET SYSTEM ALLOCATON - PAIUTE (Line 26 X Line 28)	$ (1,275,994)
32	O & M RATIO (WP C-2, ADJ. 3, SH 20)	95.85%
33	O & M SUBTOTAL (Line 28 X Line 29)	$ (1,223,040)
34	ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 20)	57.58%
35	SYSTEM ALLOCATION - PAIUTE (Line 30 X Line 31)	$ (704,227)

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SURREBUTTAL
EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANUALIZED FICA, MEDICARE, FUTA, AND SUTA

LINE NO.	DESCRIPTION	(A) ARIZONA DIRECT	(B) CORPORATE DIRECT	(C) SYSTEM ALLOCABLE	(D) TOTAL
	ANNUALIZED FICA				
1	RUCO ANNUALIZED LABOR (SUR-8, PG. 3, L 9)	$ 64,924,825	$ 2,922,055	$ 36,632,763	
2	SALARIES NOT SUBJECT TO FICA (RUCO DR 2.08)	693,076	233,025	2,989,398	
4	LABOR SUBJECT TO FICA (Line 1 - Line 2)	$ 64,231,749	$ 2,689,030	$ 33,643,365	
5	FICA RATE	6.20%	6.20%	6.20%	
6	TOTAL ANNUALIZED FICA (Line 4 X Line 5)	$ 3,982,368	$ 166,720	$ 2,085,889	
	ANNUALIZED MEDICARE				
7	ANNUALIZED LABOR (Line 1)	$ 64,924,825	$ 2,922,055	$ 36,632,763	
8	MEDICARE RATE	1.45%	1.45%	1.45%	
9	TOTAL ANNUALIZED MEDICARE (Line 7 X Line 8)	$ 941,410	$ 42,370	$ 531,175	
10	TOTAL FICA AND MEDICARE (Line 6 + Line 9)	$ 4,923,778	$ 209,090	$ 2,617,064	$ 7,749,932
	FUTA				
11	TAX BASE FACTOR	$ 7,000	$ 7,000	$ 7,000	
12	NUMBER OF EMPLOYEES (WP, ADJ. 3, SH 4)	1171	39	502	
13	TAX BASE (Line 11 X Line 12)	$ 8,197,000	$ 273,000	$ 3,514,000	
14	FUTA RATE	0.80%	0.80%	0.80%	
15	TOTAL FUTA (Line 13 X Line 14)	$ 65,576	$ 2,184	$ 28,112	$ 95,872
	SUTA				
16	TAX BASE FACTOR	$ 7,000	$ 22,000	$ 22,000	
17	NUMBER OF EMPLOYEES (WP, ADJ. 3, SH 4)	1171	39	502	
18	TAX BASE (Line 16 X Line 17)	$ 8,197,000	$ 858,000	$ 11,044,000	
19	SUTA RATE	0.06%	0.30%	0.30%	
20	TOTAL SUTA (Line 18 X Line 19)	$ 4,918	$ 2,574	$ 33,132	$ 40,624
	NET OF PAIUTE (SEE NOTE A)			$ (606,430)	
21	TOTAL LABOR LOADING (Sum Of Lines 11, 16 & 21)	$ 4,994,273	$ 213,848	$ 2,071,878	$ 7,886,428
22	COMPANY AS FILED (WP C-2, ADJ. 3, SH 5)	$ 5,329,017	$ 218,963	$ 2,742,440	$ 8,290,420
23	DIFFERENCE (Line 21 - Line 22)	$ (334,744)	$ (5,115)	$ (670,562)	$ (1,010,422)
	LESS:				
24	PERCENT INDIRECT TIME (WP C-2, ADJ. 3, SH 4)	13.53%	12.33%	12.33%	12.73%
25	INDIRECT TIME (Line 23 X Line 24)	$ (45,307)	$ (631)	$ (82,669)	$ (128,606)
26	NET ANNUALIZED LABOR LOADING (L 23 - L 25)	$ (289,438)	$ (4,485)	$ (587,893)	$ (881,816)
27	O & M RATIO (WP C-2, ADJ. 3, SH 2)	81.02%	100.00%	96.51%	91.44%
28	O & M SUBTOTAL (Line 26 X Line 27)	$ (234,494)	$ (4,485)	$ (567,391)	$ (806,369)
29	ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 15)	100.00%	100.00%	57.58%	70.15%
30	RUCO ADJUSTMENT (Line 28 X Line 29)	$ (234,494)	$ (4,485)	$ (326,703)	$ (565,682)

NOTE (A)
PAIUTE ADJUSTMENT

LINE NO.	DESCRIPTION	AMOUNT
31	RUCO ADJUSTED 920	$ 14,035,006
32	RUCO ADJUSTED 930	13,956
33	RUCO ADJUSTED 935	86,926
34	SUBTOTAL (Sum Of Lines 23, 24 & 25)	$ 14,135,888
35	PAIUTE ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 19)	-4.29%
36	NET SYSTEM ALLOCATON - PAIUTE (Line 34 X Line 35)	$ (606,430)

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SURREBUTTAL
EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANUALIZED LABOR

LINE NO.	ACOUNT CODE	(A) ARIZONA DIRECT COMPANY AS FILED Co. WP, Adj. 3	(B) ARIZONA DIRECT RUCO ADJUSTMENT Pro Rated Pg 3	(C) ARIZONA DIRECT RUCO AS ADJUSTED Col. (A) - (B)	(D) CORPORATE DIRECT COMPANY AS FILED Co. WP, Adj. 3	(E) CORPORATE DIRECT RUCO ADJUSTMENT Pro Rated Pg 3	(F) CORPORATE DIRECT RUCO AS ADJUSTED Col. (D) - (E)	(G) SYSTEM ALLOCATED COMPANY AS FILED Co. WP, Adj. 3	(H) SYSTEM ALLOCATED RUCO ADJUSTMENT Pro Rated Pg 3	(I) SYSTEM ALLOCATED RUCO AS ADJUSTED Col. (G) - (H)
	OPERATIONS									
1	813	$ -	$ -	$ -	$ 466,263	$ (10,431)	$ 455,832	$ -	$ -	$ -
2	851	-	-	-	-	-	-	-	-	-
3	870	4,514,052	(297,579)	4,216,473	306,811	(6,864)	299,947	-	-	-
4	871	12,372	(816)	11,556	349,654	(7,822)	341,832	-	-	-
5	874	3,444,633	(227,080)	3,217,553	-	-	-	-	-	-
6	875	1,294,752	(85,354)	1,209,398	-	-	-	-	-	-
7	878	3,818,483	(251,725)	3,566,758	-	-	-	-	-	-
8	879	4,511,165	(297,389)	4,213,776	-	-	-	-	-	-
9	880	4,121,590	(271,707)	3,849,883	28,484	(637)	27,847	-	-	-
10	901	2,353,532	(155,151)	2,198,381	-	-	-	-	-	-
11	902	3,380,842	(222,875)	3,157,967	-	-	-	-	-	-
12	903	8,721,804	(574,966)	8,146,838	1,365,563	(30,550)	1,335,013	1,572,645	(20,342)	1,552,303
13	905	245,780	(16,203)	229,577	-	-	-	-	-	-
14	908	181,489	(11,964)	169,525	-	-	-	-	-	-
15	909	-	-	-	-	-	-	-	-	-
16	910	517	(34)	483	-	-	-	-	-	-
17	920	-	-	-	-	-	-	29,919,071	(387,001)	29,532,070
18	922	-	-	-	-	-	-	-	-	-
19	930	-	-	-	-	-	-	29,786	(385)	29,401
20	SUBTOTAL	$36,601,011	$ (2,412,842)	$34,188,169	$ 2,516,775	$ (56,305)	$ 2,460,470	$31,521,502	$ (407,728)	$31,113,774
	MAINTENANCE									
21	885	$ 1,460,701	$ (96,294)	$ 1,364,407	$ 103,666	$ (2,319)	$ 101,347	$ -	$ -	$ -
22	886	9,036	(596)	8,440	-	-	-	-	-	-
23	887	4,945,102	(325,995)	4,619,107	-	-	-	-	-	-
24	889	736,861	(48,576)	688,285	-	-	-	-	-	-
25	892	3,503,130	(230,936)	3,272,194	-	-	-	-	-	-
26	893	742,977	(48,979)	693,998	-	-	-	-	-	-
27	894	99,171	(6,538)	92,633	-	-	-	-	-	-
28	935	448,253	(29,550)	418,703	-	-	-	184,361	(2,385)	181,976
29	SUBTOTAL	$11,945,231	$ (787,463)	$11,157,768	$ 103,666	$ (2,319)	$ 101,347	$ 184,361	$ (2,385)	$ 181,976
30	TOTALS	$48,546,242	$ (3,200,305)	$45,345,937	$ 2,620,441	$ (58,624)	$ 2,561,817	$31,705,863	$ (410,113)	$31,295,750

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SURREBUTTAL
EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANUALIZED LABOR LOADING

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		ARIZONA DIRECT			CORPORATE DIRECT			SYSTEM ALLOCATED		
LINE NO.	ACOUNT CODE	COMPANY AS FILED Co. WP, Adj. 3	RUCO ADJUSTMENT Pro Rated Pg 4	RUCO AS ADJUSTED Col. (A) - (B)	COMPANY AS FILED Co. WP, Adj. 3	RUCO ADJUSTMENT Pro Rated Pg 4	RUCO AS ADJUSTED Col. (D) - (E)	COMPANY AS FILED Co. WP, Adj. 3	RUCO ADJUSTMENT Pro Rated Pg 4	RUCO AS ADJUSTED Col. (G) - (H)
	OPERATIONS									
1	813	$ -	$ -	$ -	$ 216,923	$ (784)	$ 216,139	$ -	$ -	$ -
2	851	-	-	-	-	-	-	-	-	-
3	870	2,333,170	(21,777)	2,311,393	160,225	(579)	159,646	-	-	-
4	871	6,332	(59)	6,273	163,074	(590)	162,484	-	-	-
5	874	1,783,068	(16,642)	1,766,426	-	-	-	-	-	-
6	875	669,372	(6,248)	663,124	-	-	-	-	-	-
7	878	1,978,084	(18,463)	1,959,621	-	-	-	-	-	-
8	879	2,339,375	(21,835)	2,317,540	-	-	-	-	-	-
9	880	2,130,208	(19,883)	2,110,325	12,804	(46)	12,758	-	-	-
10	901	1,220,925	(11,396)	1,209,529	-	-	-	-	-	-
11	902	1,749,700	(16,331)	1,733,369	-	-	-	-	-	-
12	903	4,510,540	(42,100)	4,468,440	633,581	(2,291)	631,290	754,251	(16,211)	738,040
13	905	127,091	(1,186)	125,905	-	-	-	-	-	-
14	908	93,944	(877)	93,067	-	-	-	-	-	-
15	909	-	-	-	-	-	-	-	-	-
16	910	256	(2)	254	-	-	-	-	-	-
17	920	-	-	-	-	-	-	14,343,283	(308,277)	14,035,006
18	922	-	-	-	-	-	-	-	-	-
19	930	-	-	-	-	-	-	14,263	(307)	13,956
20	SUBTOTAL	$18,942,065	$ (176,798)	$18,765,267	$ 1,186,607	$ (4,290)	$ 1,182,317	$15,111,797	$ (324,794)	$14,787,003
	MAINTENANCE									
21	885	$ 755,990	$ (7,056)	$ 748,934	$ 53,906	$ (195)	$ 53,711	$ -	$ -	$ -
22	886	4,643	(43)	4,600	-	-	-	-	-	-
23	887	2,558,597	(23,881)	2,534,716	-	-	-	-	-	-
24	889	381,282	(3,559)	377,723	-	-	-	-	-	-
25	892	1,814,423	(16,935)	1,797,488	-	-	-	-	-	-
26	893	383,721	(3,582)	380,139	-	-	-	-	-	-
27	894	51,149	(477)	50,672	-	-	-	-	-	-
28	935	231,762	(2,163)	229,599	-	-	-	88,835	(1,909)	86,926
29	SUBTOTAL	$ 6,181,567	$ (57,696)	$ 6,123,871	$ 53,906	$ (195)	$ 53,711	$ 88,835	$ (1,909)	$ 86,926
30	TOTALS	$25,123,632	$ (234,494)	$24,889,138	$ 1,240,513	$ (4,485)	$ 1,236,028	$15,200,632	$ (326,703)	$14,873,929

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SURREBUTTAL
EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
REMOVING SALARIES OF SALES AND MARKETING EMPLOYEES

LINE NO.	ACCOUNT CODE	(A) DIRECT EMP'S SALARIES IN SALES/MRKT'G	(B) SYSTEM ALLOCABLE EMP'S SALARIES IN SALES/MRKT'G	(C) NO. OF EMPLOYEES
	INFORMATION FROM COMPANY RESPONSE TO RUCO DATA REQUEST NUMBER 2.08.b			
1		$ (76,567)		1
2		(75,965)		2
3		(71,972)		3
4		(69,784)		4
5		(85,440)		5
6		(76,898)		6
7		(76,026)		7
8		(67,153)		8
9		(71,879)		9
10		(83,776)		10
11		(93,764)		11
12		(100,608)		12
13			$ (84,367)	13
14			(99,256)	14
15			(89,679)	15
16			(78,026)	16
17			(85,794)	17
18			(72,339)	18
19			(91,792)	19
20			(91,424)	20
21			(87,373)	21
22			(99,226)	22
23		(58,385)		23
24		(62,896)		24
25		(70,924)		25
26		(72,660)		26
27		(76,949)		27
28		(67,338)		28
29		(67,842)		29
30		(73,103)		30
31		(67,348)		31
32		(70,584)		32
33		(82,998)		33
34		(86,966)		34
35		(93,299)		35
36		(103,221)		36
37		(120,921)		37
42	TOTALS	$ (2,125,266)	$ (879,276)	
43	ALLOCATION FACTOR	100.00%	87.25%	
44	ALLOCABLE TOTAL (See SUR-RLM-8, Page 3, Line 2)	$ (2,125,266)	$ (767,168)	$ (2,892,434)

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SURREBUTTAL
EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 10
INJURIES AND DAMAGES - SELF INSURED RETENTION NORMALIZATION

LINE NO	DESCRIPTION	REFERENCE	(A) 14 YEAR TOTAL	(B) TOTAL AZ ACCRUAL
1	Claims Paid			
2	< $1,000,000	Response To RUCO DR 14	$ 8,557,891	
3	At $1,000,000	Response To RUCO DR 14	10,000,000	
4	> $1,000,000 < $10,000,000	Response To Rebuttal Testimony - Johnson (less claims over $10 M)	29,547,300	
5	Total Claims Paid	(Sum Of Lines 2, 3 & 4)	$ 48,105,191	
6	14 Year Average	Line 5 / 14 Years		$ 3,436,085
	Less:			
7	FERC Allocation Factor	Co. Sch. C-1, Sh 18		4.29%
8	FERC Allocation	Line 6 X Line 7		(147,408)
9	Net System Allocable	Sum Of Lines 6 & 8		$ 3,288,677
10	Arizona 4-Factor	Co. Sch. C-1, Sh 19		57.58%
11	Net Arizona Allocated	Line 9 X Line 10		$ 1,893,620
12	Company Injuries And Damages Expenses As Filed	Sch. C-2, Adj. No. 10, Column (f), Line 8		$ 2,161,296
13	Difference	Line 11 - Line 12		$ (267,676)
14	RUCO ADJUSTMENT TO INJURIES AND DAMAGES EXPENSE (See SUR-RLM-7, Page 1, Column (G))			$ (267,676)

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SURREBUTTAL
EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 14
MISCELLANEOUS ADJUSTMENTS

LINE NO	DESCRIPTION	(A) RUCO ADJUSTMENTS ALLOCABLE TOTAL	(B) ALLOC'N FACTOR	(C) ARIZONA TOTAL	(D) RUCO AS ADJUSTED
	Arizona Direct Accounts				
1	870 - Operation Supervision And Engineering	$ (25,337)	100.00%	$ (25,337)	
2	875 - Measuring And Regulating Expenses - General	N/A	100.00%	-	
3	880 - Other Expenses	(162,828)	100.00%	(162,828)	
4	Sub Total Distribution	$ (188,165)			$ (188,165)
5	RUCO GOODWILL REDUCTION		20.00%	$ (37,633)	
6	REVISED SURREBUTTAL ADJUSTMENT				$ (150,532)
7	902 - Meter Reading	$ (10,715)	100.00%	$ (10,715)	
8	903 - Customer Records And Collection Expenses	N/A	100.00%	-	
9	Sub Total Customer Accounts	$ (10,715)			$ (10,715)
10	RUCO GOODWILL REDUCTION (20% Of Line 9)		20.00%	$ (2,143)	
11	REVISED SURREBUTTAL ADJUSTMENT (Line 9 - Line 10)				$ (8,572)
12	908 - Customer Assistance Expenses	N/A	100.00%	$ -	
13	910 - Miscellaneous Customer Service And Information Expenses	N/A	100.00%	-	
14	Sub Total Customer Service And Information Expenses	$ -			$ -
15	Sub Total Arizona Direct Accounts	$ (198,880)			$ (159,104)
	System Allocable Accounts To Arizona				
16	903 - Customer Records And Collection Expenses	N/A	55.40%	$ -	
17	Sub Total Customer Accounts	$ -			$ -
18	921 - Office Supplies And Expenses	$ (170,593)	57.58%	$ (98,227)	
19	923 - Outside Services Employed	(27,768)	57.58%	(15,989)	
20	930 - Miscellaneous General Expenses	(57,664)	57.58%	(33,203)	
21	Sub Total Administrative And General Expenses	$ (256,025)			$ (147,419)
22	Sub Total System Allocable Accounts To Arizona	$ (256,025)			$ (147,419)
23	RUCO GOODWILL REDUCTION (20% Of Line 22)		20.00%	$ (29,484)	
24	REVISED SURREBUTTAL ADJUSTMENT (Line 22 - Line 23)				(117,935)
25	RUCO ADJUSTMENT TO MISCELLANEOUS ADJUSTMENTS (L 6 + L 24) (See SUR-RLM-7, Page 1, Column (I))				$ (277,039)

References:
Column (A): See Testimony, SUR-RLM
And Workpapers RLM-11WP(870) Pages 1 To 4, RLM-11WP(880) Pages 1 To 18, RLM-11WP(902) Pages 1 To 3, RLM-11WP(921) Pages 1 To 13, RLM-11WP(923) Page 1, RLM-11WP(930) Page 1
Column (B): Company Schedule C-2, Adjustment No. 14
Column (C): Column (A) X Column (B)
Column (D): Sums Of Column (C)

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	(A) DESCRIPTION	(B) PROPOSED SCHEDULE NO.	(C) BILLING DETERMINANTS NUMBER OF BILLS	(D) BILLING DETERMINANTS SALES (THERMS)	(E) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(F) PROPOSED MARGIN RATES COMMODITY CHARGE	(G) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(H) MARGIN AT PROPOSED RATES COMMODITY CHARGE	(I) TOTAL MARGIN
	Single-Family Residential Gas Service	G-5							
1	Basic Service Charge per Month		8,870,882		$ 10.11		$ 89,657,934		$ 89,657,934
2	Commodity Charge All Therms			261,997,418		0.494952		129,676,151	129,676,151
3	Total Single-Family Residential Gas Service		8,870,882	261,997,418			$ 89,657,934	$ 129,676,151	$ 219,334,085
	Low Income Residential Gas Service	G-5							
4	Basic Service Charge per Month		320,907		10.11		$ 3,243,407		$ 3,243,407
5	Commodity Charge All Therms			9,417,993		0.494952		4,661,455	4,661,455
						0.494952		-	-
6	Total Low Income Residential Gas Service		320,907	9,417,993			$ 3,243,407	$ 4,661,455	$ 7,904,862
	Multi-Family Residential Gas Service	G-6							
7	Basic Service Charge per Month		694,674		8.84		$ 6,143,435		$ 6,143,435
8	Commodity Charge All Therms			14,775,511		0.494952		7,313,169	7,313,169
						0.494952		-	-
9	Total Multi-Family Residential Gas Service		694,674	14,775,511			$ 6,143,435	$ 7,313,169	$ 13,456,604
	Multi-Family Low Income Residential Gas Service	G-6							
10	*Basic Service Charge per Month*		51,446		8.84		$ 454,969	$ -	$ 454,968.69
11	Commodity Charge All Therms			1,195,957		0.494952		591,941.51	591,941.51
						0.494952		-	-
12	Total Multi-Family Low-Income Gas Service		51,446	1,195,957			$ 454,969	$ 591,942	$ 1,046,910
13	Total Residential Gas Service		9,937,910	287,386,879			99,499,745	142,242,716	241,742,462
	Master Metered Mobile Home Park Gas Service	G-20							
30	Basic Service Charge per Month		2,265		$ 138.84		$ 314,502		$ 314,502
31	Commodity Charge per Therm			2,394,942		0.306845		734,875	734,875
32	Total Master Metered Mobile Home Park Gas Service		2,265	2,394,942			314,502	734,875	1,049,377
	General Gas Service - Small	G-25(S)							
	Basic Service Charge per Month								
1	Former Small Gas Service Customers		197,569		$ 34.71		$ 6,857,576		$ 6,857,576
2	Former Medium Gas Service Customers		96		$ 34.71		3,328		3,328
3	Former Essential Agriculture Customers		144		$ 34.71		4,992		4,992
	Commodity Charge per Therm								
4	Transportation Customers			614		0.656800		403	403
5	Sales Customers			3,697,553		0.656800		2,428,553	2,428,553
6	Total Small General Gas Service		197,809	3,698,167			$ 6,865,896	$ 2,428,956	$ 9,294,852

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	(A) DESCRIPTION	(B) PROPOSED SCHEDULE NO.	(C) BILLING DETERMINANTS NUMBER OF BILLS	(D) BILLING DETERMINANTS SALES (THERMS)	(E) PRESENT MARGIN RATES BASIC SERVICE CHARGE	(F) PRESENT MARGIN RATES COMMODITY CHARGE	(G) MARGIN AT PRESENT RATES BASIC SERVICE CHARGE	(H) MARGIN AT PRESENT RATES COMMODITY CHARGE	(I) TOTAL MARGIN
	General Gas Service - Medium	G-25(M)							
	Basic Service Charge per Month								
7	Former Small Gas Service Customers		191,097		$ 48.59		$ 9,286,104		$ 9,286,104
8	Former Medium Gas Service Customers		3,703		48.59		179,965		179,965
9	Former Large Gas Service Customers		12		48.59		582		582
10	Former Armed Forces Customers		24		48.59		1,165		1,165
11	Former Essential Agriculture Customers		515		48.59		25,044		25,044
	Commodity Charge per Therm								
	Transportation Customers								
12	Former Small Gas Service Customers			99,043		0.381181		37,753	37,753
13	Former Medium Gas Service Customers			83,249		0.381181		31,733	31,733
	Sales Customers			-					
14	Former Small Gas Service Customers			39,993,998		0.381181		15,244,951	15,244,951
15	Former Medium Gas Service Customers			1,704,269		0.381181		649,635	649,635
16	Former Large Gas Service Customers			4,931		0.381181		1,880	1,880
17	Former Armed Forces Customers			3,757		0.381181		1,432	1,432
18	Former Essential Agriculture Customers			130,417		0.381181		49,713	49,713
19	Total Medium General Gas Service		195,352	42,019,665			$ 9,492,860	$ 16,017,095	$ 25,509,955
	General Gas Service - Large	G-25(L)							
	Basic Service Charge per Month								
20	Former Small Gas Service Customers		4,370		$ 208.26		$ 910,017		$ 910,017
21	Former Medium Gas Service Customers		79,287		208.26		16,512,179		16,512,179
22	Former Large Gas Service Customers		120		208.26		24,960		24,960
23	Former Armed Forces Customers		24		208.26		4,992		4,992
	Commodity Charge per Therm								
	Transportation Customers								
24	Former Small Gas Service Customers			79,960		0.260520		20,831	20,831
25	Former Medium Gas Service Customers			2,633,367		0.260520		686,044	686,044
26	Former Large Gas Service Customers			308,963		0.260520		80,491	80,491
	Sales Customers			-					
27	Former Small Gas Service Customers			2,869,954		0.260520		747,680	747,680
28	Former Medium Gas Service Customers			131,577,776		0.260520		34,278,613	34,278,613
29	Former Large Gas Service Customers			1,030,608		0.260520		268,494	268,494
30	Former Armed Forces Customers			164,814		0.260520		42,937	42,937
31	Total Large General Gas Service		83,800	138,665,443			$ 17,452,149	$ 36,125,091	$ 53,577,240
	General Gas Service - Transportation Eligible	G-25(TE)							
	Basic Service Charge per Month								
32	Former Medium Gas Service Customers		60		$ 1,041.29		$ 62,401		$ 62,401
33	Former Essential Agriculture Customers		252		1,041.29		262,085		262,085
34	Former Large Gas Service Customers		1,678		1,041.29		1,747,233		1,747,233
35	Former Armed Forces Customers		60		1,041.29		62,401		62,401
36	Demand Charge Per Month			6,989,384		0.059565		4,995,850	4,995,850
	Commodity Charge per Therm								
	Transportation Customers								
37	Former Medium Gas Service Customers					0.088067		-	-
38	Former Essential Agriculture Customers			4,330,261		0.088067		381,351	381,351
39	Former Large Gas Service Customers			25,225,778		0.088067		2,221,546	2,221,546
	Sales Customers			-					
40	Former Medium Gas Service Customers			992,285		0.088067		87,387	87,387
41	Former Essential Agriculture Customers			4,945,057		0.088067		435,494	435,494
42	Former Large Gas Service Customers			45,369,513		0.088067		3,995,534	3,995,534
43	Former Armed Forces Customers			2,924,591		0.088067		257,559	257,559
44	Total Transportation Eligible General Gas Service		2,049	83,787,486			$ 2,134,120	$ 12,374,721	$ 14,508,841
45	Total General Gas Service		479,010	268,170,761	-	-	$ 35,945,024	$ 66,945,663	$ 102,890,887

SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	(A) DESCRIPTION	(B) PROPOSED SCHEDULE NO.	(C) BILLING DETERMINANTS NUMBER OF BILLS	(D) BILLING DETERMINANTS SALES (THERMS)	(E) PRESENT MARGIN RATES BASIC SERVICE CHARGE	(F) PRESENT MARGIN RATES COMMODITY CHARGE	(G) MARGIN AT PRESENT RATES BASIC SERVICE CHARGE	(H) MARGIN AT PRESENT RATES COMMODITY CHARGE	(I) TOTAL MARGIN
	Air Conditioning Gas Service	G-40							
	Basic Service Charge								
1	With Other Service (No Basic Service Charge)		60		$ -		$ -		$ -
2	Basic Service Charge		389		34.71		13,486		13,486
	Commodity Charge per Therm								
3	Transportation Customers			614,147		0.097061		59,610	59,610
4	Sales Customers			1,179,288		0.097061		114,463	114,463
5	Total Air Conditioning Gas Service		448	1,793,435			$ 13,486	$ 174,073	$ 187,559
	Street Lighting Gas Service	G-45							
	Commodity Charge per Therm Of Rated Capacity								
6	All Usage		348	97,538	$ -	$ 0.552048	$ -	$ 53,846	$ 53,846
7	Total Street Lighting Gas Service		348	97,538			$ -	$ 53,846	$ 53,846
	Gas Service For Compression On Customer's Premises	G-55							
	Basic Service Charge								
8	Small		264		$ 34.71	$ -	$ 9,152	$ -	$ 9,152
9	Large		324		485.94		157,251		157,251
10	Residential		1,318		10.11		13,325		13,325
	Commodity Charge per Therm								
11	Transportation Customers					0.12765		-	-
	Sales Customers								
12	Small			178,034		0.12765		22,726	22,726
13	Large			1,854,237		0.12765		236,693	236,693
14	Residential			77,848		0.12765		9,937	9,937
15	Total Gas Service For Compression On Customer's Premises		1,906	2,110,119			$ 179,728	$ 269,356	$ 449,084
	Electric Generation Gas Service	G-60							
	Basic Service Charge								
16	General Service - Small		60		$ 34.71		$ 2,080		$ 2,080
17	General Service - Medium				48.59		-		-
18	General Service - Large		84		208.26		17,472		17,472
19	General Service - Transportation Eligible		108		1,041.29		112,322		112,322
20	Essential Agriculture		24		208.26		4,992		4,992
	Commodity Charge per Therm								
21	Transportation Customers			-		0.09687		-	-
22	Sales Customers			14,655,467		0.09687		1,419,693	1,419,693
23	Total Electric Generation Gas Service		276	14,655,467			$ 136,867	$ 1,419,693	$ 1,556,560
	Small Essential Agriculture User Gas Service	G-75							
24	Basic Service Charge		434		$ 208.26		$ 90,482	$ -	$ 90,482
	Commodity Charge per Therm								
25	Transportation Customers			152,234		0.21095		32,114	32,114
26	Sales Customers			2,723,713		0.21095		574,574	574,574
27	Total Small Essential Agriculture Gas Service		434	2,875,947			$ 90,482	$ 606,688	$ 697,169
	Natural Gas Engine Gas Service	G-80							
	Basic Service Charge								
28	Off-Peak Season (October - March)		3,619		$ -	$ -	$ -	$ -	$ -
29	On-Peak Season (April - September)		3,619		138.84		502,349		502,349
	Commodity Charge per Therm								
30	Transportation Customers			-		0.15069		-	-
31	Sales Customers			20,772,070		0.15069		3,130,114	3,130,114
32	Total Natural Gas Engine Gas Service		7,237	20,772,070			$ 502,349	$ 3,130,114	$ 3,632,463
33	Total Tariff Sales		10,429,835	600,257,156			136,682,182	215,577,225	352,259,406
34	Optional Gas Service	G-30	324	101,647,104	$ 1,576.36	0.04951	$ 510,740	$ 5,032,592	$ 5,543,332
35	Special Contract Service	B-1	271	30,410,785	$ 681.56	0.06413	$ 184,703	$ 1,950,134	$ 2,134,837
36	Other Operating Revenues						$ 11,434,480		$ 11,434,480
37	Total Revenue		10,430,430	732,315,046			$ 148,812,105	$ 222,559,951	$ 371,372,055
38	Recommended Annual Revenue Requirement								$ 371,372,057
39	Difference								$ (2)

Southwest Gas Corporation
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

SURREBUTTAL
TYPICAL BILL ANALYSIS
SINGLE-FAMILY RESIDENTAL GAS SERVICE

COMPARISON OF PRESENT & PROPOSED RATE STRUCTURE

LINE NO.	DESCRIPTION	CONSP'TION (THERMS)	PRESENT SCHEDULES	PROPOSED SCHEDULES	DOLLAR INCREASE	PERCENT INCREASE
			SUMMER			
			May-October Break - 20 Therms	May-October Break - 8 Therms		
	Company					
1	25% Average Usage	3	$ 11.19	$ 19.74	$ 8.55	76.43%
2	75% Average Usage	9	$ 17.57	$ 26.52	$ 8.95	50.97%
3	Average Usage	12	$ 20.76	$ 28.66	$ 7.90	38.06%
4	150% Average Usage	19	$ 27.14	$ 32.93	$ 5.79	21.35%
5	200% Average Usage	25	$ 33.10	$ 37.20	$ 4.10	12.40%
	RUCO					
6	25% Average Usage	3	$ 11.19	$ 13.32	$ 2.13	19.04%
7	75% Average Usage	9	$ 17.57	$ 19.75	$ 2.18	12.40%
8	Average Usage	12	$ 20.76	$ 22.96	$ 2.20	10.60%
9	150% Average Usage	19	$ 27.14	$ 29.39	$ 2.25	8.29%
10	200% Average Usage	25	$ 33.10	$ 35.81	$ 2.71	8.20%
			SWING MONTHS			
			April & November Break - 40 Therms	April & November Break - 8 Therms		
	Company					
11	25% Average Usage	11	$ 19.59	$ 19.74	$ 0.16	0.79%
12	75% Average Usage	34	$ 42.76	$ 26.52	$ (16.23)	-37.97%
13	Average Usage	45	$ 53.90	$ 28.66	$ (25.23)	-46.82%
14	150% Average Usage	68	$ 75.16	$ 32.93	$ (42.23)	-56.18%
15	200% Average Usage	91	$ 96.42	$ 37.20	$ (59.22)	-61.42%
	RUCO					
16	25% Average Usage	11	$ 19.59	$ 21.78	$ 2.19	11.20%
17	75% Average Usage	34	$ 42.76	$ 45.12	$ 2.36	5.53%
18	Average Usage	45	$ 53.90	$ 56.80	$ 2.90	5.38%
19	150% Average Usage	68	$ 75.16	$ 80.14	$ 4.98	6.63%
20	200% Average Usage	91	$ 96.42	$ 103.48	$ 7.06	7.32%
			WINTER			
			December-March Break - 40 Therms	December-March Break - 30 Therms		
	Company					
21	25% Average Usage	11	$ 19.59	$ 29.59	$ 10.01	51.09%
22	75% Average Usage	34	$ 42.76	$ 54.71	$ 11.95	27.95%
23	Average Usage	45	$ 53.90	$ 62.47	$ 8.58	15.91%
24	150% Average Usage	68	$ 75.16	$ 77.99	$ 2.83	3.76%
25	200% Average Usage	91	$ 96.42	$ 93.51	$ (2.92)	-3.03%
	RUCO					
26	25% Average Usage	11	$ 19.59	$ 21.78	$ 2.19	11.20%
27	75% Average Usage	34	$ 42.76	$ 45.12	$ 2.36	5.53%
28	Average Usage	45	$ 53.90	$ 56.80	$ 2.90	5.38%
29	150% Average Usage	68	$ 75.16	$ 80.14	$ 4.98	6.63%
30	200% Average Usage	91	$ 96.42	$ 103.48	$ 7.06	7.32%
	PROPOSED AVERAGE RESIDENTIAL TOTAL ANNUAL GAS SERVICE COSTS					
31	**Company**		$ 447.93	$ 479.17	$ 31.24	6.97%
32	**RUCO**		$ 447.93	$ 478.54	$ 30.61	6.83%
	PRO-RATED AVERAGE RESIDENTIAL MONTHLY GAS SERVICE COSTS (ANNUAL COSTS DIVIDED BY 12 MONTHS)					
33	**Company**		$ 37.33	$ 39.93	$ 2.60	6.97%
34	**RUCO**		$ 37.33	$ 39.88	$ 2.55	6.83%

RATE SCHEDULES

PRESENT BASIC SERVICE

$ 8.00

PRESENT COMMODITY RATE

1.02198
0.9378

BREAKPOINTS

SUMMER (THERMS) (May - Oct)
20

WINTER (THERMS) (May - Oct)
40

PROPOSED RATE DESIGNS

	COMPANY	RUCO
BASIC SERVICE	$ 16.00	$ 10.11
COMMODITY RATE *	1.19890 0.68436	1.02955
BREAKPOINTS		
SUMMER (THERMS) (Apr - Nov)	8	N/A
WINTER (THERMS) (Dec - Mar)	30	N/A

* - The Commodity Rate Includes Gas Costs Of $0.5346 Per Therm

EXHIBIT
tabbies
RUCO-7
Admitted

097-004

SOUTHWEST GAS CORPORATION
2004 ARIZONA GENERAL RATE CASE
* * *
RESIDENTIAL UTILITY CONSUMERS OFFICE
DATA REQUEST NO. RUCO-4
(RUCO-4-1 THROUGH RUCO-4-4)

DOCKET NO.:	G-01551A-04-0876
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	MARCH 11, 2005

Request No. RUCO 4-4:

Payroll - Please explain the components or basis on which the Company pays "Sales Incentives".

Respondent: Revenue Requirements

Response:

The components (categories) on which sales incentives are paid varies depending on the type of new customer.

Residential Subdivisions: The incentive categories are: per home, no 220V, barbeque stub, gaslight, indoor fireplace, outdoor appliances, standby generator, and CNG fuel maker. A signed SWG Facilities Extension Contract with commitments for heating, water heating, cooking, clothes drying, plus applicable amenities, is required to participate in the sales incentive compensation plan.

Custom - Random Residential: The incentive categories are: per custom home or manufactured home, no 220V, barbeque stub, gaslight, indoor fireplace, outdoor appliances, standby generator, and CNG fuel maker. A signed SWG Facilities Extension Contract with commitments for heating, water heating, cooking, clothes drying, plus applicable amenities, is required to participate in the sales incentive compensation plan. Where no gas main extension is required, resulting in a service lateral only, a signed Contract for the Installation of Natural Gas Facilities or Ingress Agreement with commitments for heating, water heating, cooking, clothes drying, plus applicable amenities, is required to participate in the sales incentive compensation plan.

Residential Conversions: The incentive categories are: a) propane conversion: heating, water heating; b) electric/oil conversion: heating, water heating, clothes

(Continued on page 2)

Response to Request No. RUCO 4-4: (continued)

drying, cooking (cooking incentive only available in conjunction with heating, water heating, drying). Where the extension of natural gas main is required, a signed SWG Facilities Extension Contract with the listed appliances to be converted is required for participation in the sales incentive compensation plan. Where no gas main extension is required, resulting in a service lateral only, a signed Contract for the Installation of Natural Gas Facilities or Ingress Agreement with listed appliance(s) is required.

Multi-Family Residential: The incentive categories are: number of uses, no 220V, barbeque stub, and gas lamps. A signed SWG Facilities Extension Contract with the committed appliance information and committed amenities is required for participation in the sales incentive compensation plan.

Commercial Developments: The incentive categories are: a) new business: natural gas booster heaters or warewashing equipment, natural gas heating units, and natural gas boilers; b) added load; c) conversion (including water pumping); d) natural gas cooling. Each Commercial new business project must have a signed SWG Facility Extension contract or Contract for the Installation of Natural Gas Facilities, whichever is applicable. The Agreement must state the nature of the installation and the committed appliance inventory as reflected in the mechanical design plans, to participate in the sales incentive compensation plan. Each Commercial Project for new Business Added Load and Conversion must be accompanied by an Incentive Compensation Plan Project Recap when applicable to participate in the sales incentive compensation plan. The verification of Added Load incentives will be performed randomly on a minimum of 25 percent of all projects submitted.

Authorized margin per customer: $45 per month

100 customers billed

Total authorized margin for month: $4,500

	1	**2**	**3**
BSC	$45	$15	$15
Per therm charge	$0	$1.00	$1.00
Actual therms billed	Irrelevant	30	25
Commodity charge	$0	$30	$25
Total revenue	$45	$45	$40
X 100 customers	$4500	$4500	$4000
Balance to CMT account	0	0	$500

Admitted

EXHIBIT

tabbies

RUCO 8

LB 10/04/05

Uniform System Of Accounts

For
Class A and B
Gas Utilities
1976

EXHIBIT
tabbies
RUCO - 9
Admitted

NATIONAL ASSOCIATION
OF
REGULATORY UTILITY
COMMISSIONERS

Note A.—Materials and supplies, meters and house regulators held in reserve, and normal spare capacity of plant in service shall not be included in this account.

Note B.—Include in this account natural gas wells shut in after construction which have not been connected with the line; also, natural gas wells which have been connected with the line but which are shut in for any reason except seasonal excess capacity or governmental proration requirements or for repairs, provided that the related production leases were acquired on or before October 7, 1969.

105.1 Production Properties Held for Future Use.

A. This account shall include the cost of production property relating to leases acquired on or after October 8, 1969, held under a definite plan for future use to ensure a future supply of natural gas for use in pipeline operations, to include: (1) Production property acquired but never used by the utility in utility service, but held for such service in the future under a definite plan, and (2) production property previously used by the utility in utility service, but retired from such service and held pending its reuse in the future, under a definite plan in utility service.

B. In the event that property recorded in this account shall no longer be needed or appropriate for future utility operations, the company shall notify the Commission of such condition and request approval of journal entries to remove such property from this account.

C. Gains or losses from the sale of land and land rights or other disposition of such property previously recorded in this account and not placed in utility service shall be recorded directly in account 414 or account 422 as appropriate or otherwise directed by the Commission. However, when determined to be significant by the Commission the gain or loss shall be transferred to account 253, Other Deferred Credits, or account 186, Miscellaneous Deferred Debits, and amortized to account 414, Gains (Losses) from Disposition of Utility Property, or account 422, Gains (Losses) from Disposition of Property.

D. The property included in this account shall be classified according to the detailed accounts (301-399) prescribed for utility plant in service and the account shall be maintained in such detail as though the property were in service.

Note.—If "full cost accounting for exploration and development costs" has been specifically approved by the Commission, then unsuccessful exploration and development costs incurred on leases acquired after October 7, 1969, shall be charged to account 338, Unsuccessful Exploration and Development Costs. Otherwise, such costs will be charged to account 796, Nonproductive Well Drilling.

106. Completed Construction Not Classified.

At the end of the year or such other date as a balance sheet may be required by the Commission, this account shall include the total of the balances of work orders for utility plant which has been completed and placed in service but which work orders have not been classified for transfer to the detailed utility plant accounts. (See note on following page.)

Note.—For the purpose of reporting to the Commission the classification of utility plant in service by accounts is required, the utility shall also report the balance in this account tentatively classified as accurately as practicable according to prescribed account classifications. The purpose of this provision is to avoid any significant omissions in reported amounts of utility plant in service.

107. Construction Work in Progress.

A. This account shall include the total of the balances of work orders for utility plant in process of construction.

B. Work orders shall be cleared from this account as soon as practicable after completion of the job. Further, if a project, such as a gas production plant, a compressor station, or a transmission line, is designed to consist of two or more units which may be placed in service at different dates, any expenditures which are common to and which will be used in the operation of the project as a whole shall be included in utility plant in service upon the completion and the readiness for service of the first unit. Any expenditures which are identified exclusively with units of property not yet in service shall be included in this account.

C. Expenditures on research and development projects for construction of utility facilities are to be included in a separate subdivision in this account. Records must be maintained to show separately each project along with complete detail of the nature and purpose of the research and development project together with the related costs.

Note.—If "full cost accounting for exploration and development costs" has been specifically approved by the Commission, then unsuccessful exploration and development costs incurred on leases acquired after October 7, 1969, shall be transferred to account 338, Unsuccessful Exploration and Development Costs. Otherwise, such costs will be charged to account 796, Nonproductive Well Drilling.

108. Accumulated Provision for Depreciation of Utility Plant in Service.

A. This account shall be credited with the following:

(1) Amounts charged to account 403, Depreciation Expense, to account 416, Costs and Expenses of Merchandising, Jobbing, and Contract Work, or to clearing accounts for current depreciation expense.

(2) Amounts of depreciation applicable to utility properties acquired as operating units or systems. (See utility plant instruction 5.)

(3) Amounts charged to account 182, Extraordinary Property Losses, when authorized by the Commission.

(4) Amounts of depreciation applicable to utility plant donated to the utility.

Note.—See General Instruction 8 and account 439 regarding adjustments for past accrued depreciation and amortization.

B. At the time of retirement of depreciable utility plant in service, this account shall be charged with the book cost of the property retired and the cost of removal, and shall be credited with the salvage value and any other amounts recovered, such as insurance. When retirements, cost of removal and salvage are

EXHIBIT
RUCO - 10
Admitted

111-009

SOUTHWEST GAS CORPORATION
2004 ARIZONA GENERAL RATE CASE
* * *

ACC LEGAL DIVISION DATA REQUEST NO. 8
SWG'S DATA REQUEST NO. STAFF-JJD-8
(STAFF-JJD-8-1 THROUGH STAFF-JJD-8-23)

DOCKET NO.: G-01551A-04-0876
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 12, 2005

Request No. STAFF-JJD-8-9:

Regarding the Direct portion of Southwest Gas Corporation's CCNC proposed Adjustment Number 20 in the amount of $1,819,949, please provide all appropriate documentation that confirms when the Plant was placed in service. In addition, regarding Account 376, Districts 36 and 42 in the amounts of $209,302 and $771,048, respectively, as shown in Work paper Schedule B-2, Adjustment 20, sheet 1, please provide information such as, but not limited to, type of main, size and length of main, system pressure, location of main (with maps if available), start and completion dates for main, and reasons for main (i.e., but not limited to, system reinforcement, safety, replacement/new, or franchise requirements) replacement.

Respondent: Revenue Requirements

Response:

Please see the attached reports which confirm when the Direct portion of the Company's CCNC, in Adjustment No. 20, was placed into service. Note that some work orders that were in the CCNC adjustment were canceled, or have not yet been placed into service as had been anticipated at the time of filing.

The first four sheets of the attachments are arranged as follows: each work order is listed separately, with the work order balance at 3/31/05 and the amount transferred to plant. The first month a transfer was made is listed, along with the in-service date. Note that the in-service dates can precede the first transfer month due to delays in the processing of paperwork. Work orders with a balance but no in-service date are still open.

Behind these first four pages of attachments are documents which provide the requested information regarding the individual work orders (except for the maps,

(Continued on page 2)

Response to Request No. STAFF-JJD-8-9: (continued)

which are all together in a group at the end). The documents supporting each work order are attached in the same order as the first four sheets. Each sheet will have either the work order number, work request number, or both. The maps are attached behind this set of documents. There is a summary of each work order for which a map was requested, and the actual maps or explanations for why there is no map are in the same order as the work orders listed on the map summary sheets. The work request numbers, which are written on the maps, are in a separate column on the summary sheets and can be cross-referenced to the work order number.

SOUTHWEST GAS CORPORATION
ARIZONA
FERC ACCOUNT 376 - MAINS
COMPLETED CONSTRUCTION NOT CLASSIFIED
FOR THE YTD ENDED AUGUST 31, 2004
ADJUSTMENT NO. 20

Line No.	District (a)	Work Order Number (b)	BI (c)	FERC Account (d)	at March 31,2005 Work Order Balance	at March 31,2005 Transferred to Plant	1st Transfer Month	In-Service Date
1	32	C4233289	9604	376	0	43,025	Dec-04	14-Sep-04
2								
3	32	C3662360	9605	376	0	50,393	Dec-04	1-Jul-04
4	32	C3668519	9605	376	918	0		
5	32	C3681448	9605	376	0	16,540	Nov-04	17-Jan-04
6	32	C4223980	9605	376	0	33,462	Dec-04	17-Sep-04
7	32	C4240722	9605	376	164	0		
8	32	C4244375	9605	376	15,608	0		14-Jul-04
9	32	C4244378	9605	376	27,142	0		27-Jun-04
10	32	C4253022	9605	376	52	0		
11	32	C4270703	9605	376	0	(725)	Sep-04	9-Sep-04
12								
13	32	C2536287	9611	376	3,018	0		
14								
15								
16	36	C3222006	9604	376	116,827	0		
17	36	C3222112	9604	376	0	213,017	Dec-04	30-Dec-04
18	36	C4262016	9604	376	0	103,420	Dec-04	27-Aug-04
19	36	C4264592	9604	376	0	30,909	Dec-04	30-Dec-04
20								
21	36	C2585555	9605	376	0	5,974	Dec-04	1-Jul-04
22	36	C3629025	9605	376	0	112,232	Dec-04	23-Oct-04
23	36	C4225145	9605	376	1,578	0		
24	36	C4234544	9605	376	0	241,009	Dec-04	29-Dec-04
25	36	C4234927	9605	376	42,000	0		
26	36	C4244953	9605	376	0	14,897	Mar-05	14-Jan-05
27	36	C4264224	9605	376	0	2,646	Sep-04	6-Aug-04
28	36	C4269542	9605	376	0	525	Oct-04	22-Jul-04
29	36	C4274671	9605	376	0	(572)	Sep-04	20-Aug-04
30								
31	36	C0366671	9635	376	657	0		
32								
33								
34	42	C2547577	9604	376	45,738	0		
35	42	C2568723	9604	376	345,856	0		
36	42	C2584157	9604	376	10,294	0		
37	42	C2589973	9604	376	20,898	0		
38	42	C3201085	9604	376	0	324,428	Oct-04	3-Sep-04
39	42	C3209649	9604	376	0	27,321	Oct-04	17-Sep-04
40	42	C3216903	9604	376	3,751	0		

Source: Company Records

SOUTHWEST GAS CORPORATION
ARIZONA
FERC ACCOUNT 376 - MAINS
COMPLETED CONSTRUCTION NOT CLASSIFIED
FOR THE YTD ENDED AUGUST 31, 2004
ADJUSTMENT NO. 20

					at March 31,2005			
Line No.	District	Work Order Number	BI	FERC Account	Work Order Balance	Transferred to Plant	1st Transfer Month	In-Service Date
	(a)	(b)	(c)	(d)				
1	42	C3635877	9604	376	0	77,499	Sep-04	21-Sep-04
2	42	C3646604	9604	376	0	64,644	Dec-04	4-Nov-04
3	42	C3660167	9604	376	0	26,546	Dec-04	25-May-04
4	42	C3663930	9604	376	3,128	0		
5	42	C3696055	9604	376	46,026	0		
6	42	C4231967	9604	376	0	7,874	Dec-04	20-Dec-04
7	42	C4233234	9604	376	cancelled			
8	42	C4233802	9604	376	(11,200)	0		
9	42	C4249546	9604	376	cancelled			
10	42	C4251567	9604	376	0	8,126	Dec-04	29-Nov-04
11	42	C4252036	9604	376	0	57,157	Dec-04	30-Sep-04
12	42	C4260769	9604	376	0	93,682	Dec-04	2-Oct-04
13	42	C4269589	9604	376	0	104,728	Dec-04	13-Sep-04
14								
15	42	C1422042	9605	376	0	281,433	Jan-05	7-Oct-04
16	42	C3664082	9605	376	0	93,578	Dec-04	20-Oct-04
17	42	C3693590	9605	376	0	68,349	Sep-04	12-Aug-04
18	42	C4231870	9605	376	0	26,295	Sep-04	11-Sep-04
19	42	C4232460	9605	376	0	30,671	Mar-05	18-Jan-05
20	42	C4254828	9605	376	cancelled			
21								
22	42	C0319485	9606	376	0	111,459	Oct-04	25-Sep-04
23	42	C3213815	9606	376	0	21,553	Jun-04	23-Aug-04
24	42	C3214516	9606	376	0	26,080	Oct-04	12-Oct-04
25	42	C3214937	9606	376	0	246,200	Oct-04	11-Oct-04
26	42	C3216934	9606	376	4,347	0		
27	42	C3638065	9606	376	0	48,811	Dec-04	8-Dec-04
28	42	C3649358	9606	376	0	84,085	Dec-04	13-Sep-04
29	42	C4230274	9606	376	0	109,390	Nov-04	4-Nov-04
30	42	C4231846	9606	376	0	14,934	Oct-04	4-Oct-04
31	42	C4231882	9606	376	0	86,362	Nov-04	6-Nov-04
32	42	C4236882	9606	376	0	49,998	Oct-04	26-Aug-04
33	42	C4239280	9606	376	0	29,220	Sep-04	30-Aug-04
34	42	C4245306	9606	376	0	11,230	Dec-04	13-Dec-04
35	42	C4246076	9606	376	0	27,093	Jan-05	29-Dec-04
36	42	C4249537	9606	376	0	18,292	Sep-04	2-Sep-04
37								
38	42	C1400917	9611	376	12,768	0		
39	42	C2584270	9611	376	7,874	0		
40								
41								

Source: Company Records

SOUTHWEST GAS CORPORATION
ARIZONA
FERC ACCOUNT 376 - MAINS
COMPLETED CONSTRUCTION NOT CLASSIFIED
FOR THE YTD ENDED AUGUST 31, 2004
ADJUSTMENT NO. 20

Line No.	District (a)	Work Order Number (b)	BI (c)	FERC Account (d)	at March 31,2005 Work Order Balance	Transferred to Plant	1st Transfer Month	In-Service Date
1	44	C4231070	9604	376	3,331	0		
2								
3	46	C4249338	9605	376	0	34,298	Sep-04	7-Sep-04
4								
5	47	C3203028	9605	376	0	37,148	Dec-04	7-Dec-04
6	47	C3682002	9605	376	55	0		
7	47	C4262595	9605	376	0	75,860	Nov-04	29-Sep-04
8								
9	48	C4272528	9604	376	0	10,982	Nov-04	17-Sep-04
10	48	C4273657	9605	376	3,405	0		
11								
12								

Source: Company Records

SOUTHWEST GAS CORPORATION
ARIZONA
GENERAL PLANT
COMPLETED CONSTRUCTION NOT CLASSIFIED
FOR THE YTD ENDED AUGUST 31, 2004
ADJUSTMENT NO. 20

					at March 31,2005			
Line No.	District (a)	Work Order Number (b)	BI (c)	FERC Account (d)	Work Order Balance	Transferred to Plant	1st Transfer Month	In-Service Date
1	34	C4701474	9715	391.1	95,802	0		
2								
3	36	C3701355	9715	391.1	0	76,401	Dec-04	23-Nov-04
4	36	C4701495	9715	391.1	0	61,639	Dec-04	22-Dec-04
5								
6	36	C4277200	9709	394	0	15,687	Nov-04	24-Nov-04
7	36	C4277278	9709	394	0	2,089	Nov-04	24-Nov-04
8								
9	36	C4273093	9713	398	0	2,577	Dec-04	7-Dec-07
10								
11								
12	42	C4268505	9002	302	0	7,082	Oct-04	26-Oct-04
13	42	C4272519	9002	302	0	424,000	Oct-04	25-Oct-04
14								
15	42	C4255076	9702	390.1	0	6,938	Oct-04	7-Oct-04
16								
17	42	C4267210	9715	391.1	0	3,262	Dec-04	9-Dec-04
18	42	C4701496	9715	391.1	0	61,639	Dec-04	22-Dec-04
19								
20	42	C4229896	9709	394	0	1,783	Sep-04	17-Sep-04
21	42	C4261890	9709	394	0	3,540	Jan-05	21-Jan-05
22								
23	42	C3208152	9712	397	0	5,251	Dec-04	9-Dec-04
24								
25	42	C3209606	9722	397.2	0	1,945	Sep-04	1-Sep-04
26	42	C3209652	9722	397.2	0	1,945	Sep-04	1-Sep-04
27	42	C3209663	9722	397.2	0	1,945	Sep-04	1-Sep-04
28								
29	42	C4272286	9713	398	0	11,405	Jan-05	24-Jan-05
30								
31								
32	47	C4701465	9715	391.1	139,944	0		
33								
34	48	C4701464	9715	391.1	112,933	0		
35								
36								

Source: Company Records

EXHIBIT
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THE VALUE LINE Investment Survey®

rt 3
Ratings & Reports

ISSUE 3
Pages 404-538
File in the binder in order of issue number, removing previous issue bearing the same number.

www.valueline.com

September 16, 2005

Dear Subscribers,

As part of our continuing effort to make *The Value Line Investment Survey* a more valuable investment resource, we are making Timeliness rank changes available on our Web site at 10:00 a.m. on Thursday mornings, instead of 12:00 noon on Friday.

You can get the latest rank changes by going to www.valueline.com and entering your user name and password.

We hope you will find the earlier availability beneficial.

Sincerely,

Jean Bernhard Buttner

ESPECIALLY NOTEWORTHY:

***Value Line** is adding three stocks to its ranks this week. **Chesapeake Energy** joins the Petroleum (Integrated) Industry on page 410; **UNOVA** (page 520) becomes a fixture of the Wireless Networking Industry; and **Penn Virginia Resource Partners** (page 532) fills out the Coal Industry.*

*There is also a trio of name changes. Royal Dutch Petroleum has become **Royal Dutch Shell** (page 422); Crompton Corp. is now **Chemtura Corp.** (page 483); and palmOne Inc. has reverted back to **Palm, Inc.** (see page 515).*

*Note that **Symbol Technologies** and **Zebra Technologies Corp.** have transferred into the Wireless Networking Industry. See, in turn, pages 519 and 523.*

*How long will rising oil prices benefit the **Petroleum (Integrated) Industry**? Our analysis begins on page 405.*

★★ Rank 1 (Highest) for Timeliness.
★ Rank 2 (Above Average).

In three parts: Part 1 is the Summary & Index. Part 2 is Selection & Opinion. This is Part 3, Ratings & Reports. Volume LXI, No. 3

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NATURAL GAS (DISTRIBUTION)

The Natural Gas Distribution sector remains ranked toward the bottom of those industries covered in *The Value Line Investment Survey*: 96 (of 98). With the winter heating season fast approaching, most of these local distribution companies are approaching their most profitable quarters. Investors should note that the key features of holding gas utility stocks are their safety and better-than-average dividend yields, rather than price performance or appreciation potential.

Industry Fundamentals

Local distribution companies are natural gas utilities that are regulated by both state and/or federal regulatory agencies. Since it is more efficient to build one pipeline system to serve a region, versus multiple distributors competing over the same location, they are allowed to operate essentially as natural monopolies. However, as a result, regulators limit the return on equity these companies are permitted to earn, typically around 10%-12%. Even so, each individual company is able to petition its regulators for rate increases to cover its added costs if necessary, but may receive only part, all, or none of the requested increase. Two such companies with rate cases on file are *Southwest Gas* and *Laclede Group*. *Southwest Gas* currently has a general rate case on file in Arizona that addresses relief and design issues. Management is hopeful of having favorable new rates in place by the beginning of 2006. Likewise, *Laclede* filed a request for a rate increase with the Missouri Public Service Commission. The proposed new rates would generate additional annual revenues of $34 million, if granted.

Nonregulated Activities

Industry deregulation has allowed gas utilities to expand their businesses beyond their normal distribution operations. These activities include retail energy marketing, energy trading, and oil and gas exploration and production. The companies that have expanded into these areas enjoy the opportunity of entering businesses without restrictions on return on equity. At *South Jersey Industries*, nonutility operations contribute nearly 25% of the company's total net income, and are its fastest-growing unit. By the 2008-2010 period, we look for this segment to represent nearly 35% of total net income. Also, *South Jersey* continues to expand its energy plant services to the gaming community, and is on track to deliver strong earnings gains. One drawback is that, as profits in nonregulated activities rise, regulatory agencies seem less likely to give out rate increases, since additional profits are being earned in these activities.

INDUSTRY TIMELINESS: 96 (of 98)

Natural Gas Prices

The high natural gas prices of late are not necessarily a good thing for the distribution industry. As a result of Hurricane Katrina, and the effects on oil production in the Gulf Coast, oil and gas prices have been on the rise recently. These prices, which are eventually passed on to customers, might lead to conservation among customers during the upcoming winter heating season, along with increased bad-debt expenses from customers unable to afford these higher utility bills, especially if gasoline prices continue to rise above current levels.

Customer Expansion

Customer expansion will be major focus at both *WGL Holdings*, which is located in the expanding Washington, D.C., Maryland, and Virginia region, and *Cascade Natural Gas*, located in the Pacific Northwest. It is projected that 600,000 new homes will be constructed in *WGL's* service territory in the next 20 years, which the company projects will allow it to sustain annual growth of 25,000-30,000 new utility customers per year. At Cascade, a favorable economic environment in its service region has resulted in a steady pace of new home and commercial construction. Also, the company has the potential to gain new customers via conversions from electricity and other fuels.

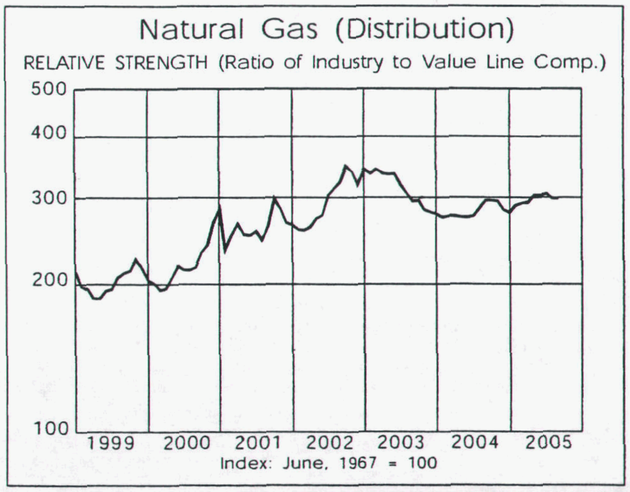
Investment Advice

The stocks in this industry cater to risk-adverse investors, who look for good stock-price stability and an above-average dividend yield. It is also noteworthy to mention that some of the companies in this sector are also expanding into nonregulated activities, which increases total-return potential, but carries additional risk. Moreover, those companies making a push into the nonregulated businesses are more likely to reduce their dividend yields, as earnings are invested back into the company to fuel further growth. Therefore, we recommend that investors pay attention to each stock individually, as with any industry, before committing to an investment.

Evan I. Blatter

Composite Statistics: Natural Gas (Distribution)

2001	2002	2003	2004	2005	2006		08-10
27611	22947	29981	33220	***35000***	***37950***	Revenues ($mill)	***42000***
1070.4	1231.5	1395.3	1735.9	***1750***	***1850***	Net Profit ($mill)	***2100***
39.7%	35.3%	37.4%	35.6%	***36.0%***	***36.0%***	Income Tax Rate	***36.0%***
3.9%	5.4%	4.7%	5.2%	***5.0%***	***4.9%***	Net Profit Margin	***5.0%***
57.4%	57.8%	55.9%	53.2%	***53.0%***	***53.0%***	Long-Term Debt Ratio	***52.5%***
41.5%	41.4%	43.7%	45.7%	***45.0%***	***45.0%***	Common Equity Ratio	***45.5%***
24342	24907	28436	31268	***33500***	***35400***	Total Capital ($mill)	***39450***
24444	25590	31732	32053	***33500***	***35000***	Net Plant ($mill)	***40000***
6.1%	6.6%	6.4%	7.1%	***7.0%***	***7.0%***	Return on Total Cap'l	***7.0%***
10.3%	11.7%	11.1%	11.9%	***12.0%***	***12.0%***	Return on Shr. Equity	***12.5%***
10.5%	11.8%	11.2%	12.0%	***12.0%***	***12.0%***	Return on Com Equity	***12.5%***
2.5%	3.9%	4.1%	5.5%	***5.5%***	***5.5%***	Retained to Com Eq	***5.5%***
76%	68%	64%	55%	***60%***	***60%***	All Div'ds to Net Prof	***60%***
16.8	14.8	14.1	13.6	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	***13.0***
.86	.81	.80	.72			Relative P/E Ratio	***.87***
4.5%	4.5%	4.5%	4.0%			Avg Ann'l Div'd Yield	***4.6%***
244%	280%	314%	308%	***315%***	***330%***	Fixed Charge Coverage	***375%***



The Cost of Capital
Estimating the Rate of Return for Public Utilities

A. Lawrence Kolbe and
James A. Read, Jr.
with George R. Hall

A Charles River Associates Study

The MIT Press
Cambridge, Massachusetts
London, England

Charles River Associates, a Boston-based firm founded in 1965, provides consulting to business, government, and the legal profession on economic, technological, and management issues. The firm's professional staff includes economists, financial experts, operations research specialists, transportation experts, engineers, and computer scientists. CRA's work covers a wide spectrum, including fuel industry, electric power, and energy economics; industry regulation; economic/engineering feasibility studies for new ventures; international trade; market forecasting for metals, minerals, and other commodities; market research for products and services; antitrust policy; communications; science and technology policy; transportation planning; and strategic planning for a broad range of industries.

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Contents

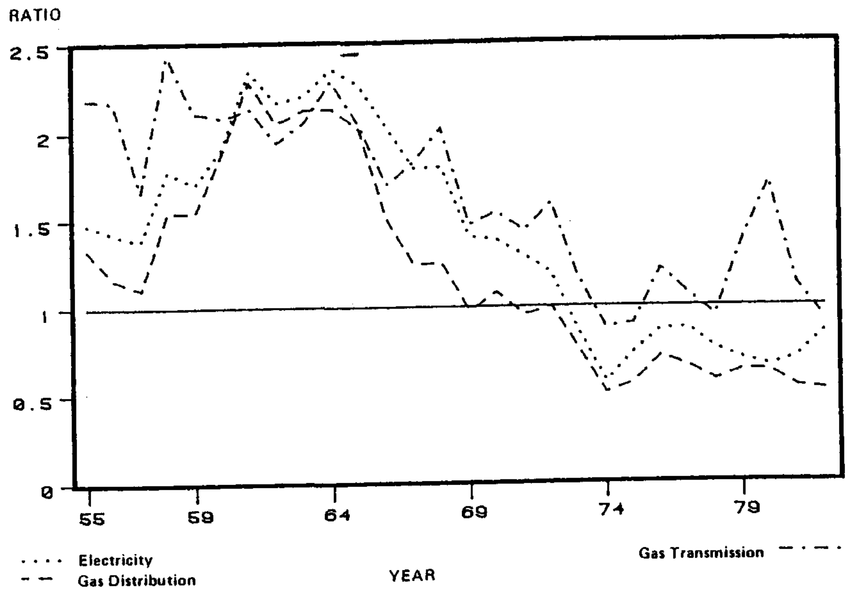

Figure 2.4
Market-to-Book Ratios for Gas and Electric Utilities
Source: Moody's Public Utility Manual.

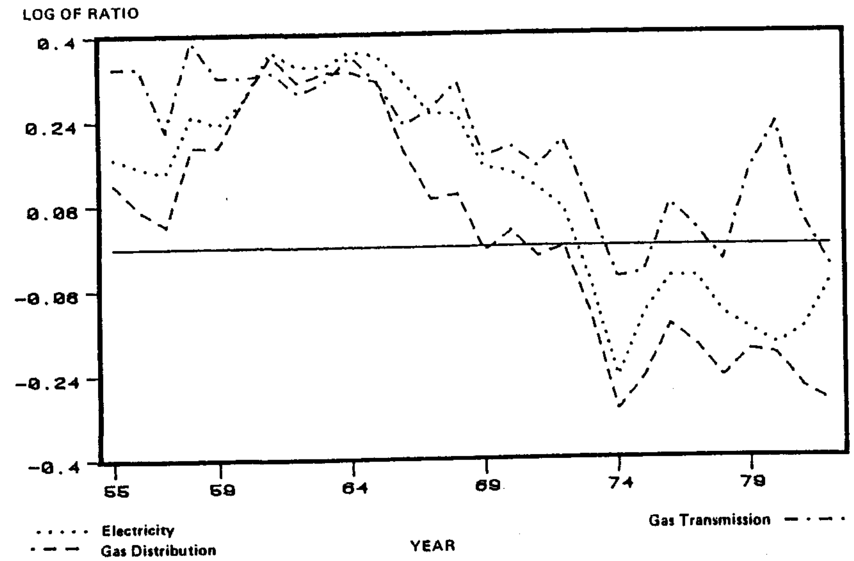

Figure 2.5
Market-to-Book Ratios for Gas and Electric Utilities: Logarithmic Scale

ACAA

ORIGINAL

BEFORE THE ARIZONA CORPORATION COMM......

COMMISSIONERS

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AZ CORP COMMISSION
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EXHIBIT
ACAA-1
Admitted

JEFF HATCH-MILLER, Chairman
MIKE GLEASON
KRISTIN K. MAYES
WILLIAM A. MUNDELL
MARC SPITZER

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. G-01551A-04-0876

DIRECT TESTIMONY OF ARIZONA COMMUNITY ACTION ASSOCIATION BY BRIAN BABIARS

Q. 1. Please state your name and business address.

A. 1. My name is Brian Babiars, and my address is 224 S. 3rd Avenue, Yuma, Arizona 85364.

Q. 2. What is your position with Arizona Community Action Association (ACAA), and what has been your experience with low-income issues?

A. 2. I am on the Board of Directors for ACAA, a position I have held since 1985. I also served on the Yuma City Council. I have also served for many years as the ACAA Energy Committee Chair. In my hometown of Yuma, Arizona, I am the Executive Director of the Western Arizona Council of Governments (WACOG), a

Community Action Program that serves Yuma, La Paz and Mohave counties. I have worked for WACOG for thirty years and have been the Executive Director since 1985. I have been an integral part of the Yuma community for more than forty years, where I have performed a number of community services, including the Yuma Elementary District as well as Western Arizona College of Board of Governors.

Q. 3. Please describe ACAA.

A. 3. ACAA is a statewide organization of people and organizations working together to find avenues of economic self-sufficiency for low-income Arizonans. There are 37 Community Action Programs (CAPs) across the state. These agencies address self-sufficiency and crisis needs of low-income individuals and families on a day-to-day basis in several ways: job counseling and training; homeless services; housing counseling; energy assistance, home repair; food assistance, senior centers, child care and in some cases Head Start programs. Community Action Agencies stand for the voiceless, the poor, the elderly and the disabled in our state and we have done so for over 40 years.

The Arizona Community Action Association serves as the statewide association for all of the above-mentioned programs. ACAA is a membership, non-partisan, private non-profit, 501 (c)(3) organization, governed by a 23 member Board of Directors. ACAA has developed a reputation throughout our history of providing credibility to and factual data on the subject of poverty in Arizona. For example, ACAA conducted and completed the 2003 ACAA Poverty Report, a study of poverty in Arizona, the third such study we have been responsible for since 1985.[1] These studies have been a result of quantitative and qualitative research, including community meetings held throughout the state, soliciting the views of people from many walks of life.

[1] Poverty in Arizona: Working Towards Solutions, ACAA, 2003

Q. 3. What is the purpose of your testimony?

A. 3. I am testifying on behalf of the Arizona Community Action Association and low-income residential customers in the Southwest Gas service territory. I am testifying for several purposes: 1) to urge the Commission to hold the low-income residential customers harmless in this rate case; 2) to urge the Commission to maintain the G-10 low-income rate; and 3) to urge the Commission to increase the marketing related to the availability of the low-income discount.

Q. 4. What has been ACAA's involvement in utility issues?

A. 4. Over the past 17 years, ACAA has worked cooperatively with Arizona's utility companies to develop public policies and programs that decrease the energy affordability gaps of low-income customers. An example of these cooperative efforts is the establishment of the Utility Repair Replacement and Deposit program by the Arizona State Legislature. This very successful program, which was modified this year to allow more of the revenue collected to flow to the community it is intended to serve, was the first of its kind in the nation and has been modeled by several other states since its inception in 1989. This is but one example of where Community Action Programs and utility companies, in this case Southwest Gas specifically, combined our respective knowledge to find solutions targeted for low-income customers.

Just as importantly, ACAA has actively engaged every energy utility company in Arizona over the past 17 years, in full cooperation with the Arizona Corporation Commission, as those companies have proposed rate changes for their residential customers. As a result of ACAA's leadership and communications, every utility company in Arizona has a low-income energy program of some type.

Q. 5. When you refer to low-income Arizonans, how many people are you talking about?

A. 5. Poverty is a problem of increasing severity in Arizona and nationally. According to the 2002 US Census figures, there are 746,145 individuals or 13.6% of our population living in poverty. Of that number, 302,013, or 20.1% are children.

Q. 6. How do these figures equate to salary or household income?

A. 6. Officially, it means that a family of three with an income of $1,306 a month, or $15,672 a year or less is living in poverty.[2]

Q. 7. What is the extent of poverty in the Southwest Gas service territory?

A. 7. According to the US Department of Agriculture, 746,145, or 13.6% of Arizonans are living in poverty. By Southwest Gas service territory by county, these numbers break down as follows:

County	**No. of People in Poverty**		**% In Poverty**	
	People	**Children**	**People**	**Children**
Cochise	19,483	8,115	16.7	25.2
Gila	8,764	3,513	17.4	27.7
Graham	6,703	2,376	22.5	25.1
Greenlee	764	296	10.2	13.0
La Paz	3,984	1,043	20.7	26.4
Maricopa	400,631	163,781	11.9	17.5
Mohave	26,754	10,152	15.7	25.8

[2] Source: US Department of Health and Human Services, 2004.

Pima	122,981	46,956	14.1	21.3
Pinal	30,808	11,332	16.3	22.0
Yuma	32,564	15,934	19.7	30.9

Q. 8. You have made it clear that your organization works to serve the needs of low-income people in Arizona. However, how can ACAA legitimately say that they represent the voice of those same people?

A. 8. It is not simply our opinion. In a series of 29 community meetings held throughout the State two years ago, in the development of the Poverty Report, 1100 people participated in community meetings across Arizona. Those participants stated they believe that conditions have gotten worse in the following areas over the past ten years: homelessness; emergency food and utility assistance; and affordable health care. Additionally, our Boards include as members, representatives of the low-income communities throughout the State. Their participation is essential to the work that we do, and their voice is heard through us throughout the State.

Q. 9. What effects do rising utility rates have on Arizona's low-income population?

A. 9. The issue of affordability has significant consequences for both the low-income ratepayer and the utility company. Although low-income households tend to consume less total energy than the average household, the burden of the energy bills, expressed as a percentage of income, is considerably greater for those who have lower incomes. In 2003, the median residential energy burden nationally was 3 percent for all households, and 10 percent for all low-income households.[3] High expenditures for energy leave less income available for other

[3] US Department of Health and Human Services, Administration for Children and Families, Office of Community Services, Division of Energy Assistance.

items including necessities such as food, clothing, medication and rent. In fact, many households must cut back on essentials in order to pay their energy bills. Any savings that a low-income family might save could be spent on necessities, and, where appropriate, reducing past arrearages in their gas bills.

Throughout Arizona, through a human and social service network that includes 37 community action programs, workers assist over 40,000 low-income families each year in paying their past due utility bills and their utility deposits. Federal Low Income Energy Assistance (LIHEAP) funds are used throughout the State, but are only serving 4% of the need in Arizona.[4] Of 436,000 eligible households, 18,600 received LIHEAP support in 2004. The total LIHEAP allocation for Arizona in 2004 was $5.7 million, however $16.4 million of additional resources were leveraged to serve families. 73% of the LIHEAP eligible households have one vulnerable individual resident, which is defined as a young child, an individual with disabilities, or a frail older individual.

Q. 10. What is the Community Action philosophy in working with families with utility problems and what works best in assisting households with continual problems of utility bill arrearages and shutoffs?

A. 10. Community Action Programs have paid over $70 million to Arizona utility companies over the last ten years. Through day to day contact with low-income utility consumers, Community Action Programs have learned that just paying past due utility bills for families **is not** the solution to the ongoing problem of unaffordable gas, electricity, water and basic housing needs.

Q. 11. What experience do Community Action Agencies have in energy efficiency and weatherization?

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[4] Apprise Study for Arizona, May 2005 (attached).

A. 11. Arizona Community Action Programs have extensive experience in operating and administering weatherization programs. Community Action Agencies have been operating the federal weatherization program since 1977 and are considered the "presumptive sponsors" of weatherization assistance programs at the local level. All sub-grantees are either non-profit organizations or units of general purpose government such as a city or county. The Community Action weatherization program mission is to reduce utility costs for low-income families, particularly for the elderly, people with disabilities, and children by improving the energy efficiency of their homes and ensuring their health and safety.

With over 40 years of experience at Community Action programs across the nation and in Arizona, we have learned that combining our philosophy of promoting family self-sufficiency with our belief in the integration of services we can make the biggest inroads to long-term problem solving. Through the comprehensive delivery of resources to troubled households we have found we can have the biggest successes in terms of self-sufficiency. Community Action Programs have learned that by targeting the resources of the low-income home weatherization program to LIHEAP recipients with the highest utility bills, a real difference can be made on a more permanent basis, thereby reducing continuing arrearage and shutoff problems. In addition, when weatherization activities are leveraged with other private and public resources, an entire energy conservation package can be applied to a home, resulting in more cost effective, long term savings. Several Community Action Agencies in Arizona have been very effective in this type of leveraging activity.

Q. 12. Why are you so concerned with the Southwest Gas rate increase?

A. 12. ACAA is concerned about the rate increase for two reasons. First, the elimination of the G-10 low-income residential rate will eliminate any structured low-income rate. It is our concern that the issues faced by the low-income will be ignored, and the discount currently available will become obsolete and eventually unavailable to eligible households. If this happens outreach, which is already an issue, will become a much greater issue.

Second, as I have articulated in this testimony, the problem of poverty in Arizona is overwhelming. What seems like an insignificant increase in rates for Southwest Gas, is significant for a low-income family in Arizona. On average, a low-income customer's bill will increase $3.60 per month. For those customers already unable to pay their bills, this adds an additional burden. For those customers who are at present just getting by, this increase has the potential to render them incapable of paying their bill.

Q. 13. What would ACAA like to see result from these proceedings?

A. 13. ACAA would like to see several actions from these proceedings:

That the Commission impose no harm to eligible low-income residential customers;

That the G-10 rate be retained; and

That the Company increase its marketing of the availability of a low-income discount rate commensurate with the need.

Q. 14. Does that conclude your testimony?

A. 14. Yes, it does.

Attachments:

1. Applied Public Policy Research Paper: Energy Needs: Profile of Low Income Households – Phoenix and Arizona.

2. Brian Babiars Vitae

RESPECTFULLY SUBMITTED this July 20, 2005.

By ______________________ ______________________

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Original and 13 copies hand delivered July 20, 2005 to:
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Docket Control
1200 W. Washington
Phoenix, AZ 85007

Applied Public Policy Research
APPRISE
Institute for Study and Evaluation

DATE: May 25, 2005 (Updated June 12, 2005)
TO: Sue Present
FROM: APPRISE Incorporated
SUBJECT: *Energy Needs: Profile of Low Income Households – Phoenix and Arizona*

Introduction

Policymakers and program managers need information about the energy needs of low-income households to make effective decisions related to program design, operations, and evaluation. Decisions need to be made at the national, state, and local levels; therefore, information needs to be developed for each of those levels as well. In this report, APPRISE uses existing data sources to develop information on the energy needs of low-income households for decision makers in Arizona. The statistics and figures presented in this report represent examples of the broad array of information that can be obtained from existing data sources. Moreover, the findings in this report provide valuable information about the needs and characteristics of low-income households in the United States, Arizona, and the Phoenix metropolitan area. The information presented in this report includes:

- National-level Data: Decision makers in Arizona can use this information to understand the similarities and differences between energy needs of Arizona households and households throughout the United States.
- State-level Data: Arizona LIHEAP managers can use this information to make decisions regarding the design of their statewide program.
- Local-level Data: Local organizations in Phoenix can use this information to improve integration of energy assistance programs with other programs designed to assist low-income households.

Methodology

Each state selects its own LIHEAP income eligibility standard.[1] For this profile, low-income households have been identified using the current Arizona LIHEAP income eligibility standard of 150 percent of the Federal Poverty Guidelines, which was $27,600 for a four-person household in 2003. APPRISE used the year-appropriate federal poverty guideline threshold values when analyzing data for this report. Throughout the document, the terms low-income, LIHEAP eligible, and LIHEAP income-eligible are used interchangeably.

[1] LIHEAP grantees can set the household income cutoff at any figure no less than 110 percent of the Federal Poverty Guidelines and no more than the greater of 150 percent of the Federal Poverty Guidelines or 60 percent of state median income (http://www.acf.dhhs.gov/programs/liheap/eligible.htm).

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APPRISE used data from various sources to generate the information provided in this report:

- National-level Data: APPRISE used data from the United States Division of Energy Assistance and the United States Energy Information Administration.
- State-level Data: APPRISE developed statistics for the state of Arizona using the Census 2000 Public Use Microdata (PUMS) Five Percent Sample and the 2002-2004 Current Population Survey Annual Social and Economic Supplement (ASEC).
- Local-level Data: APPRISE developed statistics for the Phoenix metropolitan area using the 2002 American Housing Survey (AHS) Phoenix Metropolitan Area Sample.

Impact of Poverty and Energy Prices on Low-Income Households in the United States

In the United States, the poverty rate and energy prices are increasing.

- The poverty rate has increased from 11.3% in 2000 to 12.5% in 2003.[2]
- Electricity prices have risen from 8.24 cents per kWh in 2000 to 8.94 cents in 2004.
- Natural Gas prices have risen from $7.76 per Thousand Cubic Feet in 2000 to $10.74 in 2004.[3]
- The total residential energy bill for all low-income households has increased from $25.1 billion in 2001 to $28.3 billion in 2003.[4] The total residential energy bill increase results from both the growth in the number of low-income households and the rise in average home energy bills.

Energy burden is a statistic that is often used to assess the difficulties that households have in paying their energy bills. Energy burden is defined as the percent of income spent on energy. In 2003, the median residential energy burden was 3 percent for all households and 10 percent for all low-income households.[5]

Energy gap is defined as the dollar amount needed to reduce a customer's energy burden to an amount equal to a specified energy burden percentage. In 2003, the total dollar amount needed to ensure that no American low-income household spends more than 15 percent of income on

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[2] 2000 Report: Dalaker, Joseph, U.S. Census Bureau, Current Population Reports, Series P60-214, Poverty in the United States: 2000, U.S. Government Printing Office, Washington, DC, 2001. 20-03 Report: DeNavas-Walt, Carmen, Bernadette D. Proctor, and Robert J. Mills, U.S. Census Bureau, Current Population Reports, P60-226, Income, Poverty, and Health Insurance Coverage in the United States: 2003, U.S. Government Printing Office, Washington, DC, 2004.
[3] Energy Information Administration, U.S. Department of Energy. "Monthly Energy Review, April 2005", Table 9.9 (Average Retail Prices of Electricity) and Table 9.11 (Natural Gas Prices).
[4] U.S. Department of Health and Human Services, Administration for Children and Families, Office of Community Services, Division of Energy Assistance. LIHEAP Home Energy Notebook For Fiscal Year 2003: Page 22, Figure 3-13.
[5] U.S. Department of Health and Human Services, Administration for Children and Families, Office of Community Services, Division of Energy Assistance. LIHEAP Home Energy Notebook For Fiscal Year 2003. All U.S. Households: Page 54, Figure A-2c. All Low-Income Households (150 percent of the federal poverty guidelines): Page 17, Figure 3-6.

residential energy was $4.9 billion. The total dollar amount required to reduce residential energy bills for low-income households to 25 percent of income was $2.7 billion.[6]

Impact of Poverty and Energy Prices on Low-Income Households in Arizona

Arizona policymakers and program managers can use state-level information to understand the energy needs of Arizona households. Arizona is a microcosm of the national trends in poverty and energy prices. Arizona is a growing state with an increasing population of low-income households. As shown in Table 1, the number of households in Arizona that are income-eligible for LIHEAP increased by 73,000 households in just three years, from 362,800 in 2000 to 436,000 in 2003.

Table 1
Arizona LIHEAP Eligible Households (2000 and 2003)

	Number of Households	Percent of all Arizona Households
LIHEAP Eligible Households, 2000	362,800[1]	19.1%
LIHEAP Eligible Households, 2003	436,000[2]	21.4%

[1] Source: 2000 Decennial Census PUMS 5 Percent Sample.
[2] Source: Three-year Average of the CPS ASEC 2002-2004.

Table 2 displays the changes in natural gas and electricity prices in Arizona from 1999 to 2001. Natural gas prices rose 16 percent from $8.99 per Million BTU in 1999 to $10.45 in 2001. Electricity prices remained stable between 1999 and 2001.[7] Based on the rise in national energy prices since 2000 described on page two, energy prices in the state of Arizona have probably also increased since 2001.

Table 2
Arizona Historical Energy Prices (1999-2001)

Year	Natural Gas	Electricity
1999	8.99	25.01
2000	9.33	24.73
2001	10.45	24.32

Source: Table 2. EIA Arizona State Energy Data 2001. Prices in Nominal Dollars per Million BTU.

[6] U.S. Department of Health and Human Services, Administration for Children and Families, Office of Community Services, Division of Energy Assistance. LIHEAP Home Energy Notebook For Fiscal Year 2003: Page 21, Figure 3-12.
[7] State data beyond 2001 has not been published by EIA. APPRISE will seek out additional information sources to update the energy price table data closer to 2005 for the next draft of these findings. APPRISE would appreciate assistance from any of the Arizona utility companies or NLIEC board members in obtaining state-level energy price data.

In Arizona, energy expenditures, particularly related to cooling for the elderly, disabled, and young children, are not a luxury, but a necessity due to extreme summer high temperatures that average over 100 degrees during the months of June, July, and August. High-energy prices and the need for energy have a direct impact on the amount of money that low-income households spend on energy. Table 3 shows that 26 percent of LIHEAP eligible households reported that they spent more than $1,500 per year on residential energy expenditures.

Table 3
Energy Expenditures for Arizona LIHEAP Eligible Households (1999)

	Percent of Households
No Separate Energy Bill	10%
Less than $500	12%
$500 - $999	27%
$1,000 - $1,499	25%
$1,500 - $1,999	13%
Over $2,000	13%
All LIHEAP Eligible Households	100%

Source: 2000 Decennial Census PUMS 5 Percent Sample.

Table 4 shows that 44 percent of LIHEAP eligible households in Arizona had an energy burden of 10 percent or greater (i.e., spent 10 percent or more of their income on total residential energy). Moreover, 17 percent of LIHEAP eligible households had an energy burden of 25 percent or greater. By comparison, the median residential energy burden for all US households was 3 percent.

Table 4
Energy Burden for Arizona LIHEAP Eligible Households (1999)

	Percent of Households
No Separate Energy Bill	10%
Less than 5%	17%
5 - <10%	28%
10 - <15%	16%
15 - <20%	7%
20 - <25%	4%
25% or greater	17%
All LIHEAP Eligible Households	100%

Source: 2000 Decennial Census PUMS 5 Percent Sample.

The needs of low-income Arizona households are growing faster than the State's capacity to provide energy assistance. In FY 2004, LIHEAP provided $5.7 million in home energy assistance to nearly 18,600 low-income households in Arizona.[8] However, as shown in Table 5, the LIHEAP recipient households represent only 4 percent of the LIHEAP income-eligible households in Arizona.

Table 5
Arizona LIHEAP Eligible and Recipient Households (2003)

	Number of Households
LIHEAP Eligible	436,000[1]
LIHEAP Recipient	18,600[2]

[1] Source: Three-year Average of the CPS ASEC 2002-2004.
[2] Source: LIHEAP Household Reports FY 2004.

Decision makers can estimate the severity of the energy needs for low-income Arizona households by considering the funding level needed to ensure that no low-income household spent more than a certain percentage of income on energy expenses. Although there is no standard measure of energy affordability, Table 6 displays the funding needed to reduce the energy burden of low-income Arizona households in 1999 to 5 percent, 10 percent, and 25 percent.

- 5 Percent Energy Burden: There were approximately 266,700 LIHEAP eligible households with energy burdens greater than 5 percent. It would require over $222 million of assistance to reduce their energy bills to 5 percent of household income.
- 10 Percent Energy Burden: There were approximately 166,000 LIHEAP eligible households with energy burdens greater than 10 percent. It would require over $128 million of assistance to reduce their energy bills to 10 percent of household income.
- 25 Percent Energy Burden: There were approximately 68,500 LIHEAP eligible households with energy burdens greater than 25 percent. It would require $57 million of assistance to reduce their energy bills to 25 percent of household income.

In FY 2004, LIHEAP provided $5.7 million of benefits to 18,600 households. Arizona expended $16.4 million of additional resources to supplement LIHEAP and low-income energy efficiency programs.[9] In total, Arizona households received over $22 million in energy assistance benefits. However, the dollars needed to ensure that no LIHEAP eligible Arizona household spends more than 5 percent of household income on residential energy is over $222 million.

[8] The number of FY 2004 LIHEAP recipients was obtained from Arizona's FY 2004 LIHEAP household reports. The amount of FY 2004 benefits provided was obtained from Arizona's FY 2004 LIHEAP Grantee Survey for FY 2004.
[9] http://www.liheap.ncat.org/Supplements/2004/supplement04.htm (Source Date: May 17, 2005; Download Date: June 9, 2005)

Table 6
Energy Gap for Arizona LIHEAP Eligible Households (1999)

	Number of Households	Energy Gap
Households with Energy Burdens Greater Than 5%	266,700	$222,100,000
Households with Energy Burdens Greater Than 10%	166,000	$128,400,000
Households with Energy Burdens Greater Than 25%	68,500	$57,000,000

Source: 2000 Decennial Census PUMS 5 Percent Sample.

Demographic Characteristics of Low-Income Households in Arizona

Arizona policymakers and program managers could use additional state-level information to make decisions that are more directly appropriate to the particular financial and demographic needs of low-income households in Arizona. For example, decision makers need information on demographic characteristics, which could be used to target limited State funding to the most vulnerable populations where assistance might have the greatest impact.

The LIHEAP statute identifies vulnerable and high energy-burden households as having the highest home energy needs. The statute defines a vulnerable household as those with at least one member that is a young child, an individual with disabilities, or a frail older individual. LIHEAP has explicit national performance goals for FY 2003 that include increasing the percentage of LIHEAP recipient households having at least one member age 60 years or older or age 5 years or younger.[10]

The following tables describe the characteristics of these LIHEAP eligible households. The majority of LIHEAP eligible households in Arizona have at least one vulnerable member. These households are vulnerable with respect to poverty, rising energy prices, and high energy burdens. These vulnerable individuals, in particular the elderly population, are also at great health risk due the extreme summer heat in Arizona. Table 7 shows that 73 percent of all LIHEAP eligible households reported having at least one household member who is an elderly (i.e., age 60 years or older) individual, a disabled individual, or a young (i.e., age five years or younger) child. The information reveals that targeting assistance benefits will be a challenge for Arizona decision makers, because most low-income Arizona households have vulnerable individuals.

Table 7
Arizona LIHEAP Eligible Households with Any Vulnerable Group Members (2003)

	Number of Households	Percent of Households
Household With Vulnerable Member(s)	316,500	73%

[10] U.S. Department of Health and Human Services, Administration for Children and Families, Office of Community Services, Division of Energy Assistance. LIHEAP Home Energy Notebook For Fiscal Year 2003: Page ix.

	Number of Households	Percent of Households
Household with No Vulnerable Members	119,500	27%
All LIHEAP Eligible Households	436,000	100%

Source: Three-year Average of the CPS ASEC 2002-2004.

Table 8 describes the number of LIHEAP eligible households that reported having one or more household members particularly vulnerable to unaffordable energy bills. Thirty-five percent of households reported having at least one household member who was elderly, 15 percent reported having at least one household member who was nonelderly and disabled, and 27 percent reported having at least one household member who was a young child.

Table 8
Arizona LIHEAP Eligible Households with Vulnerable Group Members (2003)

	Number of Households	Percent of Households
Household With Elderly (Age 60 or older)	154,100	35%
Household With Nonelderly Disabled	64,375	15%
Household With Young Child (Age 5 or under)	117,200	27%

Source: Three-year Average of the CPS ASEC 2002-2004.

Table 9 presents the number of LIHEAP eligible households that reported receiving income from public assistance (e.g., TANF), Supplemental Security Income, or Social Security. Six percent reported receiving public assistance benefits, another 6 percent received supplemental security income, 30 percent received social security, and 58 percent reported not having received benefits from any income program.

Table 9
Income Program Participation of Arizona LIHEAP Eligible Households (2003)

	Number of Households	Percent of Households
Public Assistance	24,600	6%
Supplemental Security Income	26,400	6%
Social Security	132,400	30%
No Income Program Participation	252,600	58%
All LIHEAP Eligible Households	436,000	100%

Source: Three-year Average of the CPS ASEC 2002-2004.

As shown in Table 10, 21 percent of all LIHEAP eligible households reported that the household was a single parent household.

Table 10
Single-Parent Arizona LIHEAP Eligible Households (2003)

	Number of Households	Percent of Households
Single-Parent Household	90,300	21%
Not Single Parent Household	345,700	79%
All LIHEAP Eligible Households	436,000	100%

Source: Three-year Average of the CPS ASEC 2002-2004.

Table 11 shows that 15 percent of all LIHEAP eligible households reported that the primary language spoken in their household is Spanish and none of the household members speak English "very well". Given this data, it is incumbent on program managers to design programs to accommodate the language needs of their population.

Table 11
Linguistically Isolated Arizona LIHEAP Eligible Households (2000)

	Number of Households	Percent of Households
Spanish Isolation	54,800	15%
Not Isolated	308,000	85%
All LIHEAP Eligible Households	362,800	100%

Source: 2000 Decennial Census PUMS 5 Percent Sample.

In Arizona, cooling needs are not a luxury for these low-income households. Households with elderly, disabled, or children are at great risk for heat-related illnesses during the extreme Arizona summer. Table 12 displays the average high temperature during the warm weather months in Arizona. The average high temperature during the months between April and October is above 90 degrees with temperatures above 100 for most of June, July, and August.

Table 12
Historical Weather Data (April – Oct)

Month	Average High Temperature
Apr	84.8
May	93.3
Jun	102.9
Jul	105.2
Aug	103.6
Sep	99.3
Oct	89.3

Source: Western Regional Climate Center.[11]

The Energy Needs of Low-Income Households in Phoenix

In addition to information related to energy needs and demographic characteristics of low-income households, policymakers and program managers at the local level might also consider information related to other factors that are associated with energy (e.g., housing) for the purposes of devising complementary direct assistance programs. These decision makers can use statistical information on the relationship between energy needs and housing adequacy to develop policies and procedures to more effectively operate energy assistance programs that complement housing programs.

As shown in Table 13, approximately 203,800 households in Phoenix, or 17.5% of all Phoenix households, are LIHEAP eligible.

Table 13
Phoenix LIHEAP Eligible Households (2002)

	Number of Households	Percent of all Phoenix Households
LIHEAP Eligible Households, 2002	203,800	17.5%

In Phoenix, the extreme summer temperature creates a substantial need for cooling energy, particularly in households with an elderly person, disabled person, or young child. These households come to rely on air conditioners not as a luxury, but as an essential appliance for health-related use. Table 14 displays the number of LIHEAP eligible households in Phoenix with and without air conditioning units[12]. With steady summer high temperatures above 100 degrees, 23,400 (or 12 percent of 203,800) LIHEAP eligible households in Phoenix do not have air conditioning units.

Table 14
Phoenix LIHEAP Eligible Households with Air Conditioning Units (2002)

	Number of Households	Percent of Households
Household With Air Conditioning Unit(s)	180,400	88%
Household with no Air Conditioning Unit	23,400	12%
All LIHEAP Eligible Households	203,800	100%

Source: 2002 American Housing Survey, Phoenix Metropolitan Area Sample.

The significant need for air conditioning comes at a price. In a table not shown here, we find that those LIHEAP eligible households with air conditioners are paying heavily for that necessity.

[11] Period of Record Monthly Climate Summary; Phoenix, Arizona. Period of Record 7/1/1948 – 12/31/1998.
[12] Evaporative coolers are not included in the American Housing Survey definition of air conditioning units and the survey does not provide data about the use of evaporative coolers.

Among the 180,400 low-income households that have an air conditioning unit, 37 percent have energy burdens at or greater than 10% and 18 percent have energy burdens at or greater than 25%.

Table 15 reports the energy burden statistics for the Phoenix Metropolitan area. In Phoenix, 37 percent of LIHEAP eligible households had an energy burden of 10 percent or greater. Moreover, 18 percent of LIHEAP eligible households had an energy burden of 25 percent or greater. As evidenced by table 4, the energy burden distribution for LIHEAP eligible households in Phoenix is very similar to the distribution for LIHEAP eligible households throughout Arizona.

Table 15
Energy Burden for Phoenix LIHEAP Eligible Households (2002)

	Number of Households	Percent of Households
No Separate Energy Bill	21,400	11%
Less than 5%	50,700	25%
5 - <10%	54,300	27%
10 - <15%	18,900	9%
15 - <20%	12,600	6%
20 - <25%	8,600	4%
25% or greater	37,300	18%
All LIHEAP Eligible Households	203,800	100%

Source: 2002 American Housing Survey, Phoenix Metropolitan Area Sample.

Policymakers and researchers often focus on shelter burden when considering the plight of low-income households. Shelter burden is defined as the percent of income spent on housing costs (including residential energy costs). According to the United States Department of Housing and Urban Development (HUD), the generally accepted definition of affordable housing is "housing for which the occupant is paying no more than 30 percent of his or her income for gross housing costs, including utilities;[13] families who pay more than 30 percent of their income for housing are considered cost burdened and may have difficulty affording necessities such as food, clothing, transportation and medical care."[14]

Some researchers have defined severe shelter burden more conservatively as a household that spends 50 percent or more of their income on shelter costs.[15] Table 16 presents shelter burden and energy burden for LIHEAP eligible households in Phoenix. Nearly all LIHEAP eligible households with an energy burden of 25 percent or greater have a severe shelter burden (i.e., spend 50 percent or more of their income on housing costs). Table 16 shows that as energy

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[13] http://www.hud.gov/offices/cpd/library/glossary/a/index.cfm (Source Date: December 6, 2002; Download Date: June 1, 2005)
[14] http://www.hud.gov/offices/cpd/affordablehousing/index.cfm (Source Date: May 27, 2005; Download Date: June 1, 2005)
[15] See Cushing N. Dolbeare. 2001. "Housing Affordability: Challenge and Context." Cityscape: A Journal of Policy Development and Research, (5)2:111-130. A Publication of the U.S. Department of Housing and Urban Development, Office of Policy Development and Research.

burden increases so does the likelihood of having a severe shelter burden. These findings suggest that energy burden has a substantial impact on housing costs.

Table 16
Shelter Burden and Energy Burden for Phoenix LIHEAP Eligible Households (2002)

	Shelter Burden					
	Less than 50%		50% or greater		All LIHEAP Eligible Households	
Energy Burden	Number	Percent	Number	Percent	Number	Percent
Less than 10%	84,700	67%	41,700	33%	126,400	100%
10 - <25%	13,600	34%	26,600	67%	40,200	100%
25% or greater	200	1%	37,100	99%	37,300	100%

Source: 2002 American Housing Survey, Phoenix Metropolitan Area Sample.

Conclusion

This report presented some examples of the broad array of information that can be developed related to the energy needs of low-income households using existing data sources. Moreover, the analyses presented here provide constructive information about the needs and characteristics of low-income households in the United States, Arizona, and the Phoenix metropolitan area.

The general findings demonstrate that low-income households in Arizona spend a significant amount of their income on residential energy. Moreover, the energy burdens of most LIHEAP eligible Arizona households are significantly higher than the energy burden of the average American household. In addition, the financial commitment to reduce energy bills to 5 percent of income for low-income Arizona households would require over $222 million more in energy assistance funding each year.

Policymakers and program managers can use information developed from existing data sources for program design, operations and evaluation at the national, state, city and neighborhood levels. However, there are limitations to what can be learned from these data. For example, the sources presented in this report do not provide information regarding how individual households manage their unaffordable energy needs. Further questions like these can be investigated by talking directly to customers via in-depth interviews and surveys, as seen in the work conducted by Roger Colton on energy insecurity.

BRIAN BABIARS

Mr. Brian Babiars is the Executive Director of Western Arizona Council of Governments (WACOG), a position he has held for the last nineteen years. Mr. Babiars began his career with WACOG in 1973 as the Physical and Natural Resources Director and became Deputy Director in 1978 prior to his appointment as Executive Director in 1985.

Mr. Babiars has an extensive history of service on numerous civic and non-profit boards. In addition, his public service includes serving on the Yuma City Council in 1971, being on the Yuma Elementary School District #1 Board from 1977 to 1979, and serving on the Arizona Western College District Governing Board from 1982 to 1992, including two terms as Chairman. Mr. Babiars currently serves on AEA Federal Credit Union Board of Directors. Mr. Babiars has served on the ACAA Board of Directors for nineteen years, serving on numerous committees, including Vice-Chairman of the Board and Chairman of the Energy Committee.

WACOG is a community action agency serving Yuma, La Paz, and Mohave Counties. Its programs include community and emergency services and community development. WACOG is the Area Agency on Aging and is the Head Start grantee for western Arizona, serving 1,060 children and their families at twenty-two sites.

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BEFORE THE ARIZONA CORPORATION COMMISSION

Jeff Hatch-Miller
Chairman
William A. Mundell
Commissioner
Marc Spitzer
Commissioner
Mike Gleason
Commissioner
Kristin Mayes
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	**Docket No G-01551A-04-0876**

NOTICE OF FILING TESTIMONY

Pursuant to the Amended Procedural Order in this matter issued on March 10, 2005, the Arizona Utility Investors Association (AUIA) hereby provides notice that it has filed the direct testimony of Walter W. Meek.

Respectfully submitted, this 26th day of July, 2005.

Walter W. Meek, President

CERTIFICATE OF SERVICE

An original and 13 copies of the foregoing testimony filed this 26th day of July, 2005, with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

EXHIBIT
tabbies
AUIA 1
Admitted

Copies of the foregoing testimony hand delivered this 26th day of July, 2005, to:

Jeff Hatch-Miller, Chairman
William A. Mundell, Commissioner
Marc Spitzer, Commissioner
Mike Gleason, Commisioner
Kristin Mayes, Commissioner
Christopher Kempley, Esq., Legal Division
Jane Rodda, Esq., Hearing Division
Ernest Johnson, Esq., Utilities Division

A copy of the foregoing testimony was mailed this 26th day of July, 2005, to:

Andrew W. Bettwy, Esq.
Southwest Gas Corporation
5241 Spring Mountain Road
Las Vegas, NV 89012

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RUCO
1110 W. Washington
Phoenix, AZ 85007

All Parties of Record

Walter W. Meek

Walter W. Meek

DIRECT TESTIMONY OF WALTER W. MEEK

I. INTRODUCTION, QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Walter W. Meek. My business address is 2100 North Central Avenue, Suite 210, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the president of the Arizona Utility Investors Association ("AUIA"), a non-profit organization formed to represent the interests of equity owners and bondholders who are invested in utility companies that are based in or do business in the State of Arizona.

Q. DOES AUIA'S MEMBERSHIP INCLUDE SHAREHOLDERS WHO HAVE EQUITY INTERESTS IN SOUTHWEST GAS CORPORATION (SWG)?

A. Yes. AUIA'S membership has always included owners of the common stock of Southwest Gas Corporation.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. On behalf of AUIA, an intervenor in this proceeding.

Q. CAN YOU SUMMARIZE YOUR EXPERIENCE IN REPRESENTING AUIA BEFORE THIS COMMISSION?

A. I represent the largest cross-section of utility stockholders in the State of Arizona and I have been involved with the utility business in Arizona for 30 years. I have been president of AUIA for 11 years and I have participated in dozens of Commission dockets on behalf of AUIA and testified in numerous proceedings. My testimony has covered topics including rate of return issues, stranded costs, disposition of regulatory assets, AFUDC, inclusion of CWIP in rate base and the impact of regulatory decisions on analyst and investor expectations.

Q. ARE YOU TESTIFYING AS AN EXPERT WITNESS?

A. Not really. Although I believe that AUIA's positions are based on solid economic principles, I try to bring a "real world" investor perspective to some of the investment and regulatory issues raised in the application.

Q. HAS AUIA INTERVENED IN PREVIOUS SOUTHWEST GAS RATE CASES?

A. Yes. AUIA was a party to the company's 2000 rate case (Docket No. G-02552A-00-0309).

Q. CAN YOU SUMMARIZE AUIA'S POSITION REGARDING THE CURRENT SOUTHWEST GAS APPLICATION?

A. Yes. AUIA agrees with the company's assertion that it needs a significant increase in margin based on a competitive authorized rate of return in order to maintain its financial integrity. However, we are equally interested in some of the rate design principles that SWG has introduced in this case. AUIA believes that the Commission has an opportunity here to engage in some truly progressive ratemaking that melds the interests of SWG shareholders and ratepayers in an important national energy context.

Q. CAN YOU OUTLINE THE KEY SUBJECTS THAT YOU WILL COVER IN YOUR DIRECT TESTIMONY?

A. Yes. My testimony will cover four subject areas:

- I will discuss the company's perennial inability to earn a reasonable rate of return and the effect of that on the company's shareholders and customers.
- As a part of a necessary financial fix and a progressive rate design for

SWG, I argue for a mechanism to decouple the company's earnings from the volume of gas it sells, particularly to residential customers.

• Among potential solutions to the earnings dilemma, I will discuss the need to provide a rate design that assures recovery of the company's fixed costs, which is not occurring today.

• Finally, I will comment briefly on the revenue requirement advanced by the company, including its proposed return on equity (ROE) and overall rate of return (ROR).

2. <u>SWG'S MEDIOCRE EARNINGS RECORD DAMAGES SHAREHOLDERS AND CUSTOMERS.</u>

Q. WHAT IS THE COMPANY'S RECORD IN TERMS OF EARNINGS?

A. In the eleven years since the end of the company's 1992 rate case, SWG has earned its authorized rate of return only once, in 1998, which was a year with below-normal temperatures and above-normal heating-degree days. In the 2004 test year, the company's indicated overall rate of return was an abysmal 4.78 percent while its return on common equity (ROE) fell to 3.56 percent compared with its authorized ROE of 11.0 percent.

Q. WHAT IS THE EFFECT OF CHRONIC UNDER-EARNING?

A. I believe there are several negative impacts. Some affect the company and its shareholders and others extend to SWG ratepayers.

Q. WHAT ARE SOME OF THE IMPACTS ON SHAREHOLDERS?

A. The most obvious effect is that the loss of retained earnings reduces shareholder equity. SWG witness Robert Mashas testified that the 11-year shortfall between actual and allowed earnings exceeded $145 million. That is money that has simply been denied to the shareholders' side of the balance sheet. Furthermore, the stock of a utility that under-earns chronically and has a highly leveraged balance sheet will be assigned a higher degree of risk and most certainly will be undervalued by the financial markets. I believe that is the case with Southwest Gas.

Q. **WHAT ARE SOME IMPACTS ON THE COMPANY'S OPERATIONS?**

A. SWG's annual customer growth is well above the industry average in its three-state service territory. As a result, it is under constant pressure to access the capital markets to fund new infrastructure. As SWG witness Jeffrey Shaw testified, if the company had earned up to its potential, its balance sheet would be stronger and its long term debt would be less. Instead, the company's balance sheet is leveraged, at about 66 percent debt, and its credit metrics produce ratings that are barely investment grade, making it more expensive to borrow money. A company that operates on the edge financially is always in danger of falling into the purgatory of junk status and the severe limitations that come with that.

Q. **AND WHAT ARE SOME IMPACTS ON SWG CUSTOMERS?**

A. All of these impacts are interrelated and they eventually fall on the customers. Higher interest expense resulting from poor credit ratings is passed on to ratepayers. In addition, it could be argued that if $145 million of retained earnings could have been applied to long term debt, SWG ratepayers have been saddled with about $60 million of unnecessary interest payments at SWG's average cost of debt. Finally, it should be said that a company with anemic earnings and poor credit ratings is always at risk for negative events that could interfere with its ability to provide safe, reliable service to its customers.

Q. WHAT ARE THE POLICY IMPLICATIONS FOR CHRONIC UNDER-EARNING?

A. It is unacceptable public policy for a regulated utility to be unable to earn its authorized rate of return despite management's best efforts to control costs and operate efficiently. It is unfair to stockholders to be denied equity gains which are rightfully theirs and it is unfair to ratepayers to have to shoulder the burden of unnecessary interest costs and the risk of deteriorated service.

Q. IS SWG MANAGEMENT BLAMELESS FOR THIS CIRCUMSTANCE?

A. I can't provide an unqualified answer to that question, but the evidence indicates strongly that SWG has hammered relentlessly on the expense side of the earnings equation. The company has increased its ratio of customers to employees from 507 per employee in 1997 to 745 in 2004. Although that may not tell the whole story, any company that can improve its employee/customer efficiency by 47% in seven years, has a firm grip on its largest cost center.

Q. IN AUIA'S VIEW, WHAT ARE THE MAIN REASONS FOR THE EARNINGS GAP?

A. As I noted earlier, AUIA was an intervenor in the company's 2000 rate case. We predicted at the end of that case that SWG would be unable to earn the rate of return authorized in that decision. I believed then, as I do now, that the Commission's continued reliance on commodity sales to generate revenues and its failure to focus on fixed cost recovery are serious structural impediments to achieving adequate earnings.

3. <u>THE COMMISSION SHOULD DECOUPLE SWG EARNINGS FROM COMMODITY SALES.</u>

Q. WHAT IS THE ISSUE REGARDING COMMODITY SALES?

A. According to Mr. Shaw, residential customers make up 95 percent of SWG's customer base and the usage behavior of nearly all of them is weather sensitive. SWG's currently authorized rates are designed to recover 62 percent of the residential margin from commodity sales. The problem is that residential sales keep dropping on a per-customer basis.

Q. HOW SERIOUS IS THE DECLINE IN USAGE?

A. According to SWG witness James Caltanach, weather-normalized usage has dropped from about 556 therms annually per customer in 1986 to 347 therms in 2004, a decrease of 37.5 percent. Significantly, base load usage in mid-summer has fallen 39 percent. Recently, overall usage has dropped 10.7 percent since the 2000 case.

The fact that the overall comparisons are normalized for weather means that they don't account for winters that are warmer than average and which exacerbate the situation. Clearly, a rate design that relies on commodity sales in the face of declining usage puts the company's earnings seriously at risk.

Q. CAN THE DECLINE BE REVERSED?

A. That is not likely. First, the weather-normalized figures show that the downward trend is institutionalized in the marketplace, caused mainly by increased efficiencies in housing and appliances. In other words it's not a fad or a reversible trend. In reality, rapid growth served by new housing stock simply assures that the downward trend will continue. Second, Mr. Caltanach demonstrates that there is measurable price elasticity in gas sales and my point would be that prices are not going anywhere but up in the foreseeable future.

Q. WHERE DO CONSERVATION RATES AND PROGRAMS FIT IN?

A. Conservation is a mixed bag. On the one hand, efficient use of any energy resource is a laudable goal. Furthermore, there is no question that the national interest is served by controlling the demand for natural gas. I would argue, however, that controlling demand in today's market, other than through price elasticity, would be accomplished better by conserving electricity than by forcing homeowners to turn down their gas thermostats.

Conservation rates should not be punitive or coercive; that is, they should not penalize me as a customer because certain choices aren't available to me, nor should they require me to make choices that are economically inefficient.

In any event, it makes no sense to hitch a utility's margin recovery to the volume of commodity sales and then pile on a conservation rate that is designed to curtail consumption even more than is already occurring in the marketplace.

Q. WHAT IS THE SOLUTION TO THIS DILEMMA?

A. The company has proposed a mechanism -- a Conservation Margin Tracker (CMT) -- to uncouple the utility's margin recovery from gas sales volumes which are subject to consumption variables, including weather. AUIA supports this proposal.

Q. HOW WOULD THE CMT WORK?

A. As I understand it, the Commission would authorize a residential margin level, which would be tracked through the CMT. If margin recovery varied from that which was authorized, the difference would be deferred and applied to customers' bills over a specific time period, either as a surcharge or as a credit.

Q. **WHAT ARE SOME BENEFITS OF THIS PROPOSAL?**

A. Depending on the details, it could remove much -- but not all -- of the uncertainty in achieving authorized rates of return by reducing the company's dependence on gas sales. It is very likely that a workable mechanism would improve the company's mediocre credit profile and could lead to better treatment from the rating agencies. The CMT would mitigate the obvious conflict between conservation efforts and SWG's revenue needs.

Q. **IS THIS A REVOLUTIONARY PROPOSAL?**

A. It is progressive, but not revolutionary. The natural gas industry and the nation's utility regulators have recently endorsed the idea of decoupling earnings from sales and three states have adopted such mechanisms. As SWG witness Steven Fetter testified, the American Gas Association (AGA) and the Natural Resources Defense Council (NRDC) led the way in July 2004 with a joint statement supporting rate true-ups "to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales."

Q. **WHAT HAVE REGULATORS DONE?**

A. At its summer session in July 2004, the National Association of Regulatory Utility Commissioners (NARUC) considered the joint statement of AGA and NRDC and the NARUC board of directors adopted a resolution encouraging state commissions to consider the ideas presented in the joint statement. In addition, three state commissions -- Oregon, California and Maryland -- have adopted varying mechanisms to decouple margin recovery from the vagaries of gas sales.

Q. COULD THIS BE CALLED A TREND?

A. It will probably vary with circumstances, but I met last week with a senior official of AGA who told me that a number of gas utilities are preparing rate cases to bring this issue to the table and that a number of jurisdictions will be giving it serious consideration. He said, "You can tell your Commission that they won't be alone if they give this idea a chance."

4. <u>THE COMMISSION SHOULD INCREASE THE COMPANY'S BASIC SERVICE CHARGE.</u>

Q. WHAT IS AUIA'S CONCERN REGARDING RECOVERY OF FIXED COSTS?

A. Since gas distribution companies have given up any profit interest in the gas commodity, the vast majority of company expenses are, in reality, fixed costs. The Arizona Corporation Commission has been slow to recognize this reality and SWG has no assured method of recovering the majority of its fixed costs.

Q. HOW SEVERE IS THE PROBLEM AT SOUTHWEST GAS?

It is quite severe. As Mr. Shaw testified, SWG's current residential rate design recovers only 38 percent of those costs through its basic service charge. The rest is relegated to the company's commodity charge and we have already demonstrated that commodity sales are an unreliable and contradictory source of cost recovery. The status quo is not appropriate if the Commission has any concern about the company's financial integrity.

Q. WHAT IS THE IMPACT ON THE COMPANY'S FINANCES?

A. From the standpoint of the investment community and the credit rating agencies, a company's inability to recover its fixed costs on a reliable and timely basis would be a serious weakness that would be reflected in elevated risk assessments and weak credit profiles. I believe that is true of SWG.

Q. HAS THE COMMISSION IGNORED THIS ISSUE IN THE PAST?

A. No. In the company's last rate case, the Commission authorized an increase in the basic service charge from $5.50 per month to $8.00, an increase of 45 percent. This was not insignificant, but it was not enough in 2004 and is well short of what is needed today.

Q. WHAT IS APPROPRIATE TODAY?

A. The company has proposed that its basic service charge be raised from $8.00 per month to $12.00, a 50 percent increase, if the CMT is adopted and a 100 percent increase, to $16 per month, without the CMT. Even this level of increase would not assure full recovery of fixed costs. AUIA supports these increases as reflective of the company's needs and the activity in other jurisdictions.

Q. ARE OTHER JURISDICTIONS TACKLING THIS ISSUE?

A. Apparently so. AGA reports that more productive fixed cost recovery mechanisms are under consideration by many state commissions. This is in response to utility financial imperatives and the desire to reduce reliance on commodity sales to achieve authorized margins.

Q, IS THE SWG PROPOSAL OUT OF LINE WITH OTHER JURISDICTIONS?

A. No. According to AGA, several cases involve higher levels of basic service charges than SWG has proposed in this proceeding. For example, I was in North Dakota a week ago in meetings at Montana Dakota Utilities (MDU) and that company reported that the North Dakota commission had just granted an increase in its basic service charge from about $5.00 per month to nearly $15.00, a 200 percent increase.

Q. IS THE MDU INCREASE MEANT TO ADDRESS A SIMILAR PROBLEM?

A. Yes. Although I am waiting for information regarding the expected percentage of cost recovery, MDU executives said their objective is to recover their fixed costs more reliably and efficiently than they have in the past.

Q. SHOULD THE COMMISSION CONSIDER ADOPTING BOTH A HIGHER BASIC SERVICE CHARGE AND THE CMT?

A. Yes. SWG witness Edward Gieseking appears to offer the higher service charge increase as an alternate to the CMT, but we believe that both approaches are appropriate. Clearly, the Commission should be moving toward cost-based rates and that is what the service charge component represents. In our view, some movement in that direction is necessary. At the same time, it seems obvious that the rate design will contain a commodity sales component for the foreseeable future and that component should be subject to the CMT.

Q. IS THE PROPOSAL TO INCREASE THE BASIC SERVICE CHARGE COMPATIBLE WITH ADOPTING THE CMT?

A. Yes. The two proposals are complimentary within the overall strategy of enabling the company to earn a larger and more acceptable portion of its authorized rate of return. The portion of costs that is not recovered through the basic service charge would be allocated to commodity sales, but would be subject to correction through the CMT.

5. <u>SOUTHWEST GAS REQUIRES A WORKABLE CAPITAL STRUCTURE AND AN ADEQUATE RATE OF RETURN ON ITS INVESTMENT.</u>

Q. HAVE YOU FORMED AN OPINION ABOUT THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. Yes. I agree with company witness Thomas Wood's analysis, which recommends a hypothetical capital structure that produces a common equity component of 42 percent compared with the company's actual equity ratio of 34.1 percent.

Q. WHY IS A HYPOTHETICAL CAPITAL STRUCTURE IMPORTANT?

A. The key is the response of the credit rating agencies. As Mr. Wood points out, SWG currently suffers with credit ratings that are barely investment grade and it must compete for investment capital with other gas distribution companies that have lower risk profiles, healthier balance sheets, better earnings, stronger interest coverages and, therefore, higher ratings than SWG. One of the three rating agencies, Moody's Investor Services, currently has SWG on negative outlook.

Q. HOW DOES A HYPOTHETICAL CAPITAL STRUCTURE HELP?

A. In the short term, the objective is to prevent any deterioration in the company's credit quality because there is no room for it. A capital structure for ratemaking purposes that approximates that of a higher rated company is potentially attractive to the rating agencies. The structure proposed by Mr. Wood is similar to that of a company rated BBB in Standard & Poor's rating scheme and should help to insulate SWG from negative consequences.

Q. WOULD THIS STRUCTURE PLACE A BURDEN ON RATEPAYERS?

A. I concur with Mr. Wood that the difference in the equity component between the actual and hypothetical capital structures is not large enough to be a burden to ratepayers. I believe a potential deterioration in the company's credit ratings could be more damaging to ratepayers.

Q. HAVE YOU FORMED AN OPINION ABOUT THE COMPANY'S PROPOSED RATES OF RETURN?

A. Yes. To recap, Mr. Wood's overall rate of return of 9.40 percent depends, not only on his hypothetical capital structure, but on the cost of equity component of 11.95 percent recommended by SWG witness Frank Hanley. I believe both are reasonable under the circumstances.

Q. WHAT CIRCUMSTANCES ARE YOU REFERRING TO?

A. As the Commission knows, I am an advocate for basing rate-of-return decisions on real world circumstances in lieu of academic formulas. I am also a disciple of the standards set out in the *Bluefield Water Works* and *Hope Natural Gas* cases, which require that a utility's return must be sufficient to support its financial requirements and that investors must be given an opportunity to earn a return that is comparable to returns on investments in other enterprises having corresponding risks.[1]

In this instance, SWG exhibits far more risk than the comparable gas utilities cited by Mr. Hanley, all of which have better credit profiles, higher ratings, healthier balance sheets, larger equity components and stronger interest coverages than SWG and are probably growing more slowly. In addition, the two groups of proxy companies achieved average ROEs of 12.11 percent and 11.7 percent during his study period, while SWG earned only 6.74 percent in Arizona.

Q. HOW SHOULD THESE CIRCUMSTANCES AFFECT THE ROE?

[1] See *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923), and *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944)

A. SWG's authorized ROE should reflect the additional risk that this company presents to investors compared with its peers and it should reflect what is being achieved in the marketplace by comparable entities.

Q. HOW IS THE CMT FACTORED INTO THE RECOMMENDED ROE?

A. Mr. Hanley's recommendation of 11.95 percent ROE assumes that the company will receive no protection in rate design from declining consumption. However, he estimates that the value of the CMT, if adopted, is approximately 25 basis points, which would reduce the recommended ROE to 11.7 percent. That, in turn, would lower the proposed overall rate of return to 9.29 percent.

6. <u>CONCLUSION</u>

Q. DO YOU HAVE SOME CONCLUDING REMARKS?

A. Very briefly. It has been shown clearly that Southwest Gas has failed consistently to earn its authorized rate of return due to the failure of its approved rate design to provide fixed cost recovery and to provide protection from declining customer usage.

This earnings gap has penalized consumers with higher or unnecessary interest costs and has plunged the company to the bottom of the barrel in terms of credit quality and almost any financial comparison with comparable gas distribution companies.

The Commission has an opportunity in this case to allign shareholder and customer interests through progressive ratemaking. But let me be blunt: If the Commission is unwilling either to focus on fixed cost recovery through the basic service charge or to adopt a mechanism to uncouple earnings from gas sales, Southwest Gas will remain at the bottom of the financial barrel for the foreseeable future.

AUIA urges the Commission to respond positively to help elevate Southwest Gas to a higher level.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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BEFORE THE ARIZONA CORPORATION COMMISSION

Jeff Hatch-Miller
Chairman
William A. Mundell
Commissioner
Marc Spitzer
Commissioner
Mike Gleason
Commissioner
Kristin Mayes
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	**Docket No G-01551A-04-0876**

NOTICE OF FILING TESTIMONY

Pursuant to the Amended Procedural Order in this matter issued on March 10, 2005, the Arizona Utility Investors Association (AUIA) hereby provides notice that it has filed the surrebuttal testimony of Walter W. Meek.

Respectfully submitted, this 13th day of September, 2005.

Walter W. Meek

Walter W. Meek, President

CERTIFICATE OF SERVICE

An original and 13 copies of the foregoing testimony filed this 13th day of September, 2005, with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

EXHIBIT
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AUIA 2
Admitted

Copies of the foregoing testimony hand delivered
this 13th day of September, 2005, to:

Jeff Hatch-Miller, Chairman
William A. Mundell, Commissioner
Marc Spitzer, Commissioner
Mike Gleason, Commisioner
Kristin Mayes, Commissioner
Christopher Kempley, Esq., Legal Division
Jane Rodda, Esq., Hearing Division
Ernest Johnson, Esq., Utilities Division

A copy of the foregoing testimony was
mailed this 13th day of September, 2005, to:

Andrew W. Bettwy, Esq.
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5241 Spring Mountain Road
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Phoenix, AZ 85007

All Parties of Record

Walter W. Meek

SURREBUTTAL TESTIMONY OF WALTER W. MEEK

I. INTRODUCTION, QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Walter W. Meek. My business address is 2100 North Central Avenue, Suite 210, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the president of the Arizona Utility Investors Association ("AUIA"), a non-profit organization formed to represent the interests of equity owners and bondholders who are invested in utility companies that are based in or do business in the State of Arizona.

Q. DOES AUIA'S MEMBERSHIP INCLUDE SHAREHOLDERS WHO HAVE EQUITY INTERESTS IN SOUTHWEST GAS CORPORATION (SWG)?

A. Yes. AUIA'S membership has always included owners of the common stock of Southwest Gas Corporation.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. On behalf of AUIA, an intervenor in this proceeding.

Q. HAS AUIA INTERVENED IN PREVIOUS SOUTHWEST GAS RATE CASES?

A. Yes. AUIA was a party to the company's 2000 rate case (Docket No. G-02552A-00-0309).

Q. HAS AUIA SUBMITTED TESTIMONY PREVIOUSLY IN THIS CASE?

A. Yes. AUIA submitted my direct testimony on March 10, 2005.

Q. CAN YOU SUMMARIZE AUIA'S POSITION IN THAT TESTIMONY?

A. Yes. AUIA agreed with the company's assertion that it needs a significant increase in margin based on a competitive authorized rate of return in order to maintain its financial integrity. However, we were equally supportive of the company's proposals to uncouple its margin requirements from volumetric sales and to increase its fixed cost recovery through a major increase in its fixed monthly charge.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. In my surrebuttal, I take issue with Staff and RUCO witnesses who reject the concept of the conservation margin tracker (CMT) proposed by the company and who support inadequate increases in the fixed monthly charge. I will also include comments in response to Staff recommendations for overall revenue requirements and cost of capital.

Q. CAN YOU SUMMARIZE YOUR POSITION?

A. Yes. AUIA is chagrined that Staff and RUCO are advocating policies that will perpetuate Southwest Gas Corporation's inability to earn its authorized rate of return by continuing to couple the company's margin to declining volumetric gas sales. These policies will also sentence Southwest Gas to ongoing residence in the credit ratings basement and continuing devaluation of the company's securities.

Q. WHY DO THE STAFF AND RUCO OPPOSE A DECOUPLING MECHANISM?

A. Basically, they don't like it because it is different. Both Staff witness William Musgrove and RUCO witness Marylee Diaz Cortez describe the conservation margin tracker in pejorative terms like "extreme," "radical" and "unprecedented," but they offer no analytical evidence to show that the CMT is an inappropriate response to the problem of dependence on volume sales.

They choose to ignore the fact that three other states – California, Oregon and Maryland – have adopted similar proposals.

Mr. Musgrove and Ms. Diaz Cortez also argue that the company's CMT proposal is "unfair" because it focuses on residential customers to the exclusion of commercial users. My response is that the evidence is clear that the problem of declining usage is attributable primarily to the residential class and that's where the solution should be focused.

SWG may be amenable to a proposal to include commercial customers in the CMT and if Staff and RUCO were anxious to cure this inequity, they would provide recommendations on how to do that. Instead, they offer nothing but criticism.

Q. IS THAT THE EXTENT OF STAFF AND RUCO ARGUMENTS AGAINST THE CMT?

A. No. Both Staff and RUCO witnesses lament that it would be "unfair" under the CMT to charge residential customers "for therms they don't use." Staff witness Musgrove – in a challenging flight of gibberish – also seems to argue that SWG is off base in arguing that <u>per capita</u> usage is declining because, in fact, the proximate cause of reduced usage relates to overall customer growth. He also asserts that the profiles of the commercial and residential classes are virtually identical.

Q. HOW DO YOU RESPOND TO THESE ARGUMENTS?

A. The fairness argument is entirely specious. The way SWG's rates are structured today, the company's shareholders are forced to give up legitimate earnings under an approved rate of return because of therms the customers don't use. I don't hear Staff and RUCO sermonizing over the unfairness in that scheme.

In response to Mr. Musgrove's usage argument, if the company's margin rates are based, to any significant degree, on commodity sales and those sales don't materialize, it's largely irrelevant whether it is traceable to old customers or new ones. In fact, the evidence is clear that usage has declined among SWG's long established customers. The solution is to reduce the company's dependence on commodity sales for its earnings.

Finally, I don't know what he means by identical profiles, but the load factors for residential and general service customers are very different. They are 40 percent and 67 percent, respectively.

Q. **WHAT IS THE CONSEQUENCE OF REJECTING THE CMT?**

A. In rejecting the CMT out of hand, with no attempt to amend or improve the concept, Staff and RUCO simply wash their hands of the basic problem raised by the company in its direct case. As long as SWG is dependent on commodity sales, its earnings will be subverted by improved housing, weather, price elasticity and conservation messages and its fixed cost recovery will continue to be unacceptable.

Q. **HAVE STAFF AND RUCO RECOMMENDED INCREASING THE MONTHLY FIXED COST CHARGE?**

A. Yes. Staff proposes to raise the charge from $8.00 per month to $9.50, an increase of 18.75 percent, and RUCO proposes a new charge of $9.36, an increase of 17 percent.

Q. **WOULD THESE INCREASES HELP TO ALLEVIATE THE CURRENT COST RECOVERY PROBLEM?**

A. They would be helpful, but both fall far short of what is needed to make a real dent in the problem.

Q. WHAT KIND OF INCREASE IS NEEDED?

A. In his direct testimony, Southwest Gas CEO Jeffrey Shaw asserted that SWG's current residential rate design recovers 38 percent of costs through the fixed charge and 62 percent from commodity sales, which are subject to consumption. As far as I know, that testimony is uncontested.

According to my information, the RUCO proposal would improve the fixed charge recovery ratio to only 41 percent, while the Staff proposal would improve the ratio to 39 percent. Clearly, this is not sufficient, especially without a decoupling mechanism.

In its direct case, the company argued for a 50 percent increase in the basic monthly charge, to $12.00, in conjunction with the CMT or a 100 percent increase, to $16.00, without the CMT. To have any impact on SWG's earnings dilemma, an increase in the fixed monthly charge would have to be much closer to the company's proposal.

Q. WOULD RUCO'S FLAT RATE PROPOSAL MITIGATE THE PROBLEM RELATED TO COMMODITY SALES?

A. No. It would make it worse. RUCO wants to eliminate the two-tiered declining block structure, which would also eliminate the seasonal rate differential. In other words, the effect would be to flatten the rate structure and make every therm cost the same. But this simply increases the threat to earnings.

First, eliminating the lower cost block simply increases the likelihood that some customers will buy less gas. Second, by adding a revenue increase on top of a flattened rate structure, each therm becomes more valuable and any loss of sales will be magnified on a unit basis.

It is probably not RUCO's intention, but the fact is that any rate structure that relies heavily on commodity sales is a shell game for the company's shareholders and it doesn't matter where the pea is hidden.

Q. **DO YOU HAVE ANY REACTION TO STAFF'S AND RUCO'S POSITIONS ON REVENUE REQUIREMENTS AND COST OF CAPITAL?**

A. On balance, the recommended increases in margin requirements by Staff and RUCO are encouraging because they acknowledge that Southwest Gas is in need of serious financial relief. However, the cost-of-equity recommendations (RUCO 10.15%, Staff 9.5%) are too low, considering that similar companies with better credit profiles and stronger balance sheets are actually earning more than 12 percent return on equity in the marketplace.

Q. **WILL STAFF'S RATE OF RETURN FORMULATION ASSURE AN INVESTMENT GRADE CREDIT RATING FOR SOUTHWEST GAS?**

A. Staff Witness Stephen Hill asserts that the overall rate of return he recommends (8.40%) will give the company an opportunity to achieve pre-tax interest coverage of 2.38 times, which he says is sufficient to allow SWG to retain an investment grade rating under Standard & Poor's benchmarks. He also claims that his recommended return on equity will enable the company to achieve higher interest coverage and improve its risk profile.

Mr. Hill's calculations appear to be accurate and his credit rating projections would be comforting if the company actually had a chance to earn the rate of return he recommends. But the history of this company over the past 11 years is that it can't earn its way out of the hole created by declining gas usage and, barring snow on the ground in Gila Bend in July, it will never do so while its margin rates depend on volume sales of gas.

Q. **SHOULD SWG BE REQUIRED TO INCREASE ITS EQUITY RATIO TO 40 PERCENT, AS STAFF RECOMMENDS?**

A. This is another gross departure from reality.

I know of only two ways to increase equity. One is through retained earnings, but as Mr. Shaw testified, Southwest Gas has given up more than $145 million in net income in Arizona through its inability to earn its authorized rate of return in 10 of the last 11 years. Nothing that Staff has proposed in this case is likely to cure the SWG earnings syndrome.

The second method of increasing equity is through a common stock offering. But where is the investor who is willing to buy a high-risk security with restricted earnings potential and poor growth prospects? It's certainly not the existing shareholder who would see the value of his or her stock diluted severely by any new offering.

Oh, I nearly forgot. There is a third method. You could simply stop paying dividends and bank the money instead. But I suspect that even Mr. Hill would concede that such a strategy in today's market would consign SWG to the bottom rung of utility stocks.

In reality, if the Commission is unwilling to author a substantial change in SWG's ability to earn a reasonable rate of return, any attempt to force an increase in the company's equity ratio will simply be punitive.

Q. **DO YOU HAVE ANY FURTHER COMMENTS?**

A. The positions taken by Staff and RUCO in their rebuttal testimonies are very disappointing. They display a dedication to the status quo and business as usual when the recent history of this company and the evidence in this case point to the need for a major course correction in setting rates for Southwest Gas.

If the Commission continues down this path, it will sentence the company to a formula of inadequate earnings, poor credit ratings, high interest costs, a herniated capital structure and revolving rate cases. That is the regulatory definition of purgatory.

There is no glory in this behavior and no benefit to consumers, only short-term political gain for those who perpetuate it. Sooner or later, all of this translates into higher charges to customers.

Mr. Hill, the Staff's witness, recommended that Southwest Gas be required to develop a plan to increase the equity ratio in its capital structure. AUIA agrees with that recommendation, provided that the Commission also adopts a plan to align SWG's rates with its costs and to free the company from the oppression of commodity sales.

Q. DOES THAT CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

SWEEP

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, CHAIRMAN
MARC SPITZER
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. G-01551A-04-0876

Direct Testimony of

Jeff Schlegel

on behalf of

Southwest Energy Efficiency Project and Natural Resources Defense Council (SWEEP/NRDC)

July 26, 2005

EXHIBIT
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Direct Testimony of Jeff Schlegel, SWEEP/NRDC
Docket No. G-01551A-04-0876

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List of Exhibits

Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project and the Natural Resources Defense Council (SWEEP/NRDC).

Q. Please describe the Southwest Energy Efficiency Project (SWEEP).

A. SWEEP is a public interest organization dedicated to advancing energy efficiency as a means of promoting both economic prosperity and environmental protection in the six states of Arizona, Colorado, New Mexico, Nevada, Utah, and Wyoming. SWEEP works on state energy legislation, analysis of energy efficiency opportunities and potential, expansion of state and utility energy efficiency programs as well as the design of these programs, building energy codes and appliance standards, and voluntary partnerships with the private sector to advance energy efficiency. SWEEP is collaborating with utilities, state agencies, environmental groups, universities, and energy specialists in the region. SWEEP is funded primarily by foundations, the U.S. Department of Energy, and the U.S. Environmental Protection Agency. I am the Arizona Representative for SWEEP.

Q. Please describe the Natural Resources Defense Council (NRDC).

A. NRDC is a nonprofit organization of scientists, lawyers and environmental specialists with over 23,000 members and on-line activists in Arizona dedicated to protecting public health and the environment. NRDC has a long standing interest in minimizing the societal costs of the reliable energy services that a healthy economy requires. NRDC focuses on addressing its members' interests in receiving affordable energy services and reducing the environmental impact of energy consumption through utility procurement of cost-effective energy efficiency and other environmentally and economically sustainable resources.

Q. What are your professional qualifications?

A. I am an independent consultant specializing in policy analysis, evaluation and research, planning, and program design for energy efficiency and clean energy resources. I consult for public groups and government agencies, and I have been working in the field for over 20 years. In addition to my responsibilities with SWEEP, I am working or have worked extensively in many of the states that have effective energy efficiency programs, including California, Connecticut, Massachusetts, New Jersey, Vermont, and Wisconsin. In 1997, I received the Outstanding Achievement Award from the International Energy Program Evaluation Conference. Exhibit JS-1 summarizes my professional qualifications.

Q. What is the purpose of your testimony?

A. In my testimony I will discuss the public interest in increasing natural gas energy efficiency, summarize the savings potential and performance of gas energy efficiency programs based on studies and experience in other states, comment on the Demand Side Management (DSM) programs and funding proposed by Southwest Gas, propose modifications to the Southwest Gas DSM proposal, discuss related DSM issues including Commission approval and cost-recovery, propose a collaborative DSM working group, discuss the financial disincentive to natural gas utility support of energy efficiency, and oppose higher fixed charges for Southwest Gas customers.

The Public Interest in Increasing Natural Gas Energy Efficiency

Q. What is the public interest in increasing natural gas energy efficiency?

A. Natural gas DSM energy efficiency programs are in the public interest. Increasing gas energy efficiency will provide significant and cost-effective benefits for Southwest Gas customers, the natural gas and electric utility systems, the economy, and the environment. Increasing natural gas energy efficiency will save consumers and businesses money through lower energy bills, resulting in lower total costs for customers. Natural gas energy efficiency programs will help mitigate fuel price increases and reduce customer vulnerability and exposure to natural gas price volatility. Increasing natural gas energy efficiency will also diversify energy resources, reduce air pollution and carbon emissions, and create jobs and improve the economy. Natural gas energy efficiency is a reliable energy resource that costs less than other resources for meeting the energy needs of customers in the Southwest Gas service territory.

There are many opportunities for cost-effective natural gas energy efficiency in the Southwest Gas service territory in Arizona, as evidenced by gas DSM programs and gas DSM potential studies in other states.

The Potential for Natural Gas DSM Savings and Experience in Other States

Q. Have there been any recent studies of natural gas energy efficiency potential in the Southwest region?

A. Two such studies were completed recently by the consulting firm GDS Associates, Inc. One study was completed for a Utah Natural Gas DSM Advisory Group[1] and the other was for Public Service Company of New Mexico (PNM).[2]

Q. What do these studies of energy efficiency potential conclude?

A. Both studies indicate very substantial cost-effective and achievable natural gas savings potential. The Utah study concludes that a comprehensive and well-funded 10-year DSM effort could reduce gas use by residential and commercial customers 20 percent at the end of the 10-year period. The estimated benefit-cost ratio for this overall effort is 2.39 using the Total Resource Cost (TRC) test. The PNM study estimates that implementing a broad set of cost-effective DSM programs during 2005-2014 could reduce gas use of all customers 12% by 2014. In this case the estimated benefit-cost ratio is 1.85, again using the TRC test.

Q. What is the experience with natural gas DSM programs in other states?

A. While not as common as electric utility DSM programs, numerous gas utilities are implementing cost-effective DSM programs that are helping their customers reduce their gas consumption and gas bills. Based on a survey of America's leading natural gas DSM programs[3], here are three examples of successful gas DSM programs.

Keyspan Energy, which operates in both New York and Massachusetts, is investing about $13 million per year on a comprehensive set of gas energy efficiency programs for residential and commercial customers. Keyspan saved 430 million cubic feet of gas from all programs implemented in 2002. Their programs as a whole have a benefit-cost ratio of 2.45.

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[1] *The Maximum Achievable Cost Effective Potential for Gas DSM in Utah for the Questar Gas Company Service Area.* Final Report prepared by GDS Associates for the Utah Natural Gas DSM Advisory Group, June 2004. http://www.swenergy.org/news/Natural_Gas_DSM_Potential_in_Utah.pdf

[2] *The Maximum Achievable Cost Effective Potential for Natural Gas Energy Efficiency in the Service Territory of PNM.* Final Report prepared by GDS Associates for PNM, May 27, 2005.

[3] *Exemplary Natural Gas Energy Efficiency Programs.* Washington, DC: American Council for an Energy-Efficient Economy. Dec. 2003. http://www.aceee.org/utility/ngbestprac/ngbestpractoc.pdf

Xcel Energy implements gas DSM programs in Minnesota. The utility's rebate program for high efficiency commercial and industrial gas boilers saved 168 million cubic feet of gas in 2002 alone and operates at an average cost of $2.50 per thousand cubic feet saved.

In *Wisconsin*, DSM programs are implemented statewide by a third party program administrator. The ENERGY STAR products incentive and promotion program achieved 43% market share for ENERGY STAR clothes washers in 2003, the highest market share in the nation. The clothes washer program saved 40 million cubic feet of gas in 2002 alone with a benefit-cost ratio counting gas savings only of 1.85.

In addition, *California*[4] recently adopted cost-effective energy savings requirements for gas utilities. The requirements will provide customers relief from rising natural gas bills by tripling annual gas savings by the end of the decade (saving 444 million therms per year by 2013, equivalent to the consumption of one million households), and cutting growth in gas consumption by final consumers in half.

Q. How much is being invested in leading gas DSM programs by gas utilities in other states?

A. Gas utilities in a number of states including California, Connecticut, Massachusetts, Iowa, Vermont, and Washington are investing 0.7-2.1% of their revenues on gas DSM programs according to a survey completed in April, 2004.[5]

Southwest Gas Proposal for Increased DSM Programs and Funding

Q. Do SWEEP/NRDC support the Southwest Gas proposal for increased DSM programs and funding?

A. Yes. SWEEP/NRDC support the two existing and seven additional natural gas DSM programs, and the DSM funding increase from $0.6 million to $4.385 million, proposed by Southwest Gas. The proposed DSM programs will provide significant and cost-effective benefits for Southwest Gas customers. All Southwest Gas customer classes and segments will have an opportunity to participate in and benefit directly from at least one DSM program in the portfolio that Southwest Gas proposed.

Below is a table summarizing the Southwest Gas DSM proposal for easy reference.[6]

[4] California Public Utilities Commission. Decision D.04-09-060, September 2004.
[5] IndEco Strategic Consulting Inc. and Navigant Consulting Ltd. *DSM in North American Gas Utilities.* Report prepared for Enbridge Gas Distribution. April 2004. http://www.indeco.com/www.nsf/papers/regframeworkdsm
[6] Direct Testimony of Vivian Scott, Southwest Gas, Appendix B.

Customer Sector	Program	Funding
Residential	Low-Income Energy Conservation	$ 500,000
Residential	Energy Star Home Certification	250,000
Residential	Multi-Family New Construction	1,200,000
Residential	Residential Energy Conservation	200,000
Residential	Energy Star Appliances	800,000
Commercial/Industrial	Food Service Equipment	500,000
Commercial/Industrial	Efficient Commercial Building Design	500,000
Commercial/Industrial	Technology Information Center	35,000
Industrial	Distributed Generation	400,000
	Total	**$ 4,385,000**

Q. Do SWEEP/NRDC propose any revisions to the DSM program funding proposed by Southwest Gas?

A. Yes. SWEEP/NRDC propose that funding for the residential new construction program (ENERGY STAR Home Certification) should be increased, to at least $1 million annually, to better address the cost-effective opportunities in new construction throughout the Southwest Gas service territory. Additional DSM funding is necessary to capture energy efficiency opportunities in the fast-growing new home market, including promoting and incentivizing new homes that exceed the ENERGY STAR threshold. Also, additional DSM funding is needed to offer the program throughout the Southwest Gas service territory; the new home program should not be limited to the Tucson area as the EAP program has been in the past. Total DSM program funding would be $5.135 million with the increase in residential new construction funding.

Q. How cost-effective will the portfolio of Southwest Gas DSM programs be?

A. SWEEP/NRDC estimate that the societal benefits of the Southwest Gas DSM portfolio will be about two times the societal cost (a benefit/cost ratio of about 2.0), based on the recent natural gas DSM potential studies in Utah and New Mexico, and experience with gas DSM programs in other states. The specific costs, benefits, and cost-effectiveness of the Southwest Gas DSM portfolio and the individual DSM programs should be documented in the DSM portfolio and program plan (described below).

Q. Should Southwest Gas coordinate with electric utilities regarding DSM programs?

A. Southwest Gas should attempt to coordinate with electric utilities to jointly promote and deliver electric and natural gas energy efficiency services, particularly for new construction, where possible.

Q. Please describe the performance incentive that SWEEP/NRDC propose Southwest Gas could earn for effective DSM performance.

A. SWEEP/NRDC propose a positive performance incentive that Southwest Gas would earn if it implements effective DSM programs that meet program goals. The performance incentive mechanism should be based largely on a portion of the net economic benefits of the DSM program portfolio, supplemented with a small number of program-specific performance metrics for some programs (e.g., number of customers served in the low income program). The total incentive level should be capped at 10% of the DSM program funding, resulting in a maximum performance incentive of $513,500 in 2006, based on 2006 DSM program funding of $5.135 million. Total DSM funding would be $5.649 million including the maximum performance incentive amount.

The proposed performance incentive mechanism should be described in the DSM portfolio and program plan to be submitted by Southwest Gas (see below). The portion (%) of the net economic benefits that Southwest Gas is eligible to receive should be proposed as a component of the incentive mechanism design in the plan. The performance incentive mechanism should include a threshold for minimum performance level; if actual performance is less than the threshold Southwest Gas would not receive any incentive. The performance incentive earned should be based on actual DSM results.

Q. What is a reasonable and meaningful level of DSM effort for Southwest Gas?

A. The proposed DSM programs and the $5.649 million total DSM funding level represent a reasonable and meaningful level of DSM effort for Southwest Gas in 2006, during a year when Southwest Gas is ramping up its DSM activities. The DSM program funding of $5.135 million in 2006 is equivalent to about 0.8% of revenues, based on 2004 test year revenues.[7]

Additional cost-effective DSM programs and activities should be considered for future years (2007 and beyond), and should be implemented if approved by the Commission in the future.

Q. How should Southwest Gas recover the costs of Commission-approved DSM programs?

[7] $5.135 million of 2006 DSM program funding divided by $647.277 million of 2004 test year revenues, per Southwest Gas Schedule E-6.

A, SWEEP/NRDC agree with Southwest Gas that the current adjuster mechanism should be used to recover the costs of Commission-approved DSM programs. All customer classes should pay the surcharge in the future since there will be DSM programs to benefit all customer classes. The adjuster mechanism should be used for the programs proposed by Southwest Gas, at the level of funding SWEEP/NRDC recommend ($5.649 million in 2006). Southwest Gas should be able to increase the level of the adjuster mechanism and the associated surcharge in the future, without a rate case proceeding, if the Commission approves increases in DSM funding for previously-approved programs or if the Commission approves additional DSM programs.

Q. How should DSM programs be reviewed and approved by the Commission?

A. All DSM programs should be pre-approved by the Commission before Southwest Gas should be allowed to include the program costs in any determination of total DSM costs incurred. Southwest Gas should file a DSM portfolio and program plan describing the details of the programs and their cost-effectiveness, either as a supplemental filing in this proceeding (preferred) or within 90 days of the Commission's order in this proceeding. The DSM portfolio and program plan should describe the proposed programs, and include estimated benefits, costs, cost-effectiveness, and measurement and evaluation plans for Commission review.

Q. Is there a need for a collaborative DSM working group for Southwest Gas?

A. Yes. Southwest Gas should implement and maintain a collaborative DSM working group to solicit and facilitate stakeholder input, assist Southwest Gas in developing DSM programs, advise Southwest Gas on program implementation, and review DSM program performance including program evaluations and reports. The DSM working group should review draft DSM plans, proposals, and reports prior to Southwest Gas submitting them to the Commission. If Southwest Gas does not submit a DSM program proposal considered by the collaborative DSM working group to the Commission, any member of the working group may submit the program proposal directly to the Commission for its consideration and approval. At a minimum, Staff, RUCO, AECC, the Arizona State Energy Office, SWEEP, and NRDC should be invited to participate with Southwest Gas in the collaborative DSM working group.

Financial Disincentive to Natural Gas Utility Support of Energy Efficiency

Q. Does Southwest Gas experience a financial disincentive to its support of energy efficiency efforts when its customers respond and become more energy efficient?

A. Yes. Traditional utility regulation links the utility's financial health to the volume of natural gas sold, resulting in a financial disincentive to invest in energy efficiency and other demand-side resources that reduce natural gas sales. For Southwest Gas, energy savings by customers (which are beneficial for customers) result in lower revenues for the company and threaten recovery of utility fixed costs. In general, this financial disincentive can reduce utility support and enthusiasm for cost-effective resources such as energy efficiency programs that minimize the long-term cost of providing service. It also could impede potentially crucial utility support for energy-efficiency standards, building energy codes, and other policies that serve societal interests and reduce energy use without requiring any direct utility investment.

The financial disincentive is particularly strong for natural gas utilities that have experienced an overall trend of declining gas usage per customer, which is the situation for Southwest Gas.

Q. How should this financial disincentive be addressed?

A. SWEEP/NRDC agree that the issue of the financial disincentive to natural gas utility support of energy efficiency should be addressed in Arizona in a timely manner. We believe this will be necessary if Arizona wants to fully tap the potential for its lowest cost natural gas resource – cost-effective energy efficiency improvements.

While not prejudging the specific Conservation Margin Tracker (CMT) mechanism proposed by Southwest Gas, SWEEP/NRDC believe that the gas utility financial disincentive issue and a full analysis of the pros and cons of mechanisms for removing the financial disincentive, including but not limited to the CMT, should be reviewed and evaluated prior to Commission adoption of a specific mechanism. This issue would benefit from a broader and more in-depth discussion, in this proceeding or in another forum. SWEEP/NRDC recommend that a wider range of mechanisms that break the link between the utility's financial health and energy sales, including decoupling, be further explored by the Commission before a particular mechanism is adopted. SWEEP/NRDC also recommend that the Commission give consideration to the following questions, among others, when developing or reviewing any proposed mechanism to address the financial disincentive for natural gas utilities:

1. Who should bear responsibility for weather variations and associated weather risk?
2. Who should bear the risks of variations in economic growth from forecasted levels and overall demographic and energy usage trends?

If not addressed fully in this proceeding, in the manner described above, SWEEP/NRDC recommend that the issue of the financial disincentive and potential mechanisms to address it be discussed in the DSM policy process, either through additional comments on the proposed DSM policies or through additional DSM policy workshops. Proposed policies or mechanisms resulting from the DSM policy process should then be submitted to the Commission.

Q. Have other states adopted mechanisms to reduce or remove the financial disincentive that gas utilities face if they implement effective energy efficiency programs?

A. Yes. A number of states including California[8], Massachusetts, Minnesota, New Hampshire, and Oregon have done so either through adopting some form of gas sales-revenue decoupling mechanism, or a positive financial incentive based on DSM program performance.[9]

Fixed Charges

Q. Should the Commission approve higher fixed charges for Southwest Gas?

A. No. SWEEP/NRDC oppose higher fixed charges for natural gas customers because higher fixed charges would mute and reduce the price signal customers would receive when they reduce energy use and become more energy efficient, and therefore would reduce the power they have over their own energy bills.

Conclusion

Q. Please provide an overall conclusion for your testimony.

A. SWEEP/NRDC support the DSM programs proposed by Southwest Gas and recommend the modifications and additions to their DSM proposal described herein. Furthermore, we urge the Commission to implement programs, policies, and mechanisms that *encourage* cost-effective energy efficiency, not discourage it, for customers and for natural gas utilities. Increasing natural gas energy efficiency will provide significant and cost-effective benefits for Southwest Gas customers, the natural gas and electric utility systems, the economy, and the environment.

Q. Does that conclude your direct testimony?

A. Yes.

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[8] California Public Utilities Commission. Decisions D.04-05-055, June 2004, for PG&E; D.05-03-023, March 2005, for SDG&E and SoCalGas.

[9] See footnotes 3 and 5.

Qualifications of Jeff Schlegel

1167 W. Samalayuca Drive
Tucson, Arizona 85704
520-797-4392; 520-797-4393 (fax)
schlegelj@aol.com

Jeff Schlegel is an independent consultant specializing in policy analysis, planning, evaluation and research, and program design for energy efficiency, renewable energy, and low-income energy programs. Mr. Schlegel has more than 20 years of experience in the energy field. He works for public groups, collaboratives, and government agencies. Currently he is working with:

- The Southwest Energy Efficiency Project (SWEEP) on energy efficiency and distributed resources issues (2002-present);
- The State of Connecticut Energy Conservation Management Board, a public board appointed by the Connecticut legislature to oversee energy efficiency, demand response, and low income programs in the state (2000-present);
- The Massachusetts Energy Efficiency Collaboratives on behalf of the non-utility parties, providing policy analysis, planning, and evaluation oversight of energy efficiency and demand response programs (1992-present).

Summaries of Recent Projects: Policy Analysis, Planning, Program Design, and Measurement and Evaluation for Energy Efficiency and Renewable Energy Programs

- Arizona representative for the Southwest Energy Efficiency Project (SWEEP), a public interest organization devoted to advancing energy efficiency in Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming (2002-present). SWEEP was launched in 2001, and is working collaboratively with state governments, utilities, and other organizations. Represents SWEEP in Arizona, and coordinates with a coalition of environmental, consumer, and renewable energy groups in Arizona and the southwest on energy efficiency and distributed resource issues. Advocates and provides technical assistance regarding policies, programs, and market rules to advance energy efficiency.

- Policy and evaluation consultant for the Massachusetts non-utility parties in the New England energy efficiency collaboratives (1992-2003). Also provided policy analysis and evaluation support for the Conservation Law Foundation (CLF) in the early period of the collaboratives. Provides policy and technical support directly to the non-utility parties in the Massachusetts collaboratives (National Grid/Massachusetts Electric, NSTAR/Boston Edison, and Northeast Utilities/Western Massachusetts Electric), and coordinates with other collaboratives in New England. Mr. Schlegel's primary responsibilities include policy analysis, resource analysis and planning, evaluation and research, and program review for commercial and industrial (C&I) as well as residential programs.

- Policy, program, and evaluation consultant for the State of Connecticut Energy Conservation Management Board (ECMB), a public board appointed by the Connecticut legislature to oversee energy efficiency, demand response, and low income programs in the state (2000-present). Serves as the lead technical and policy consultant for the ECMB regarding the Conservation and Load Management (C&LM) programs in Connecticut, funded at $89 million annually.

- Technical consultant for the New England Demand Response Initiative (NEDRI). Assisted a 50-member stakeholder group from the six New England states in developing a comprehensive, coordinated set of demand response programs for the New England regional power markets (2002-2003).

- Policy, evaluation, and protocols consultant for the New Jersey Clean Energy Collaborative, a collaborative of the New Jersey electric and gas utilities and the Natural Resources Defense Council (NRDC) on energy efficiency and low income programs (2000-2003).

- From July 1997 to March 2000, Mr. Schlegel served as the lead technical consultant to the California Board for Energy Efficiency (CBEE). CBEE was a public advisory board that provided recommendations to the California Public Utilities Commission on the $275 to $300 million of energy efficiency programs operated in the State of California annually by the four largest investor-owned utilities. In this full-time position Mr. Schlegel served as the CBEE's technical coordinator and lead technical consultant; developed and drafted the energy efficiency policy rules adopted by the California Public Utilities Commission; assisted the CBEE in formulating policy and program recommendations for consideration by the Commission; examined policy initiatives proposed by utilities and parties; reviewed and prepared comments on three years of annual program plans proposed by the utilities; recommended new program concepts and alternatives to utility proposals based on compilation and assessment of ideas from other states and regions; tracked and monitored program performance and market progress; and developed an RFP for independent administration of energy efficiency programs. As part of this assignment Mr. Schlegel did extensive analysis of options for administration, management, and implementation of publicly-funded energy efficiency programs.

- Conducted a scoping study of market effects and market transformation due to California utility energy efficiency programs for the California PUC in conjunction with Lawrence Berkeley National Laboratory (1996). Reviewed the performance of C&I and residential programs in terms of how they have impacted and changed markets.

- Reviewed California demand-side management (DSM) measurement and evaluation activities for the California Public Utilities Commission (1994-1999), including the activities of the California Demand-Side Management Measurement Advisory Committee (CADMAC). This included independently reviewing the California measurement and evaluation protocols, providing independent assessments of utilities' requests for protocol waivers, and reviewing and commenting on evaluation studies and program performance.

- Participated in electric retail competition workshops and meetings, as part of the Arizona Corporation Commission's consideration of electric restructuring, on behalf of the Arizona Community Action Association (ACAA) (1994-1997). Represented low income customers and coordinated with consumer and environmental groups. Advocated and provided technical and policy support for energy efficiency and low income weatherization programs.

- Directed the evaluation of DSM shareholder incentive mechanisms for the California Public Utilities Commission (1992-1994). This study evaluated the effects of incentive mechanisms used for four California utilities and assessed the effectiveness of DSM incentives as a regulatory strategy. The evaluation also assessed the balance of risks and rewards for ratepayers and shareholders, evaluated market transformation, explored the role of measurement and evaluation in the regulatory process, and compared and contrasted various options for performance incentive mechanisms. As part of this study, Mr. Schlegel reviewed evaluation studies of DSM programs offered by the four major California utilities. Testified on these issues before the Commission in 1993-1994, and participated in a series of workshops on shareholder incentives in 1993.

- Reviewed the performance of DSM programs in New England for the Conservation Law Foundation and the Pew Charitable Trust (1994-1996). Compared evaluation results to planning estimates (costs, savings, and cost-effectiveness) to determine the overall performance and reliability of DSM.

- Conducted a verification audit of Pacific Gas and Electric Company's commercial and industrial custom rebate program as a consultant for the Commission Advisory and Compliance Division of the California Public Utilities Commission (CPUC) (1992-1993). As part of this project, designed the overall verification approach, developed the stratified sampling plan, reviewed the program results, and developed the procedures for adjusting engineering estimates based on the verification results.

- Executive Director (1990-1992) and Research Director (1985-1990) at Wisconsin Energy Conservation Corporation (WECC), a not-for-profit research, policy analysis, resource planning, and program design firm. Performed evaluations of utility, government, and public energy efficiency programs. Conducted research on new and emerging energy efficiency technologies, designed programs, and developed resource plans including portfolios of DSM and energy efficiency programs. As Executive Director, responsible for all operations of the not-for-profit corporation, with an annual budget of over $2 million. WECC grew from three to twenty-two employees during Mr. Schlegel's tenure.

Low-Income Program Experience

Mr. Schlegel has worked with utilities and government agencies to design, implement, and evaluate low-income programs. From October 1998 through May 2002 he worked with the Arizona Department of Economic Security on the REACH program, a low-income self-sufficiency program, performing evaluation, analysis, and reporting tasks. From 1994 to 1997 he worked with the Arizona Community Action Association (ACAA) on a series of energy affordability and weatherization/DSM programs. As part of this work he analyzed options, designed and evaluated different program approaches, and prepared comments for several rate cases. He has also represented ACAA on electric restructuring issues in workshops before the Arizona Corporation Commission.

Mr. Schlegel managed many projects with the State of Wisconsin Low Income Weatherization Assistance Program over an eight-year period from 1985 through 1993. He led the development of the integrated computerized energy audit system and other software used by the State of Wisconsin in its program. In 1989 he directed an evaluation and review of the use of the computerized energy audit system and infiltration procedures in the State of Wisconsin program. He also conducted an evaluation of the Wisconsin Gas Company low-income programs.

Awards

Mr. Schlegel is the winner of the 1997 Outstanding Achievement Award from the International Energy Program Evaluation Conference.

Publications and Presentations

Mr. Schlegel has presented at more than 60 major national, regional, and statewide energy conservation conferences, and is the author of many published papers and articles. He has presented papers at several major conferences including the National Association of Regulatory Utility Commissioners (NARUC) Conference, the International Conference on Energy Program Evaluation, the American Council for an Energy Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Buildings, the National Energy Services and DSM Conferences, the E-Source Conference, the Affordable Comfort Conference, the National Low-Income Energy Consortium Conference, the National Community Action Foundation Conference, the National Consumer Law Center Conference, and the National Department of Energy Weatherization Conference. He was a panel leader for the 1990 and 1996 ACEEE Summer Studies on Energy Efficiency.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, CHAIRMAN
MARC SPITZER
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. G-01551A-04-0876

Surrebuttal Testimony of

Jeff Schlegel

on behalf of

Southwest Energy Efficiency Project and Natural Resources Defense Council (SWEEP/NRDC)

September 13, 2005

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~~Admitted~~

Surrebuttal Testimony of Jeff Schlegel, SWEEP/NRDC
Docket No. G-01551A-04-0876

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Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project and the Natural Resources Defense Council (SWEEP/NRDC).

Q. Did you sponsor direct testimony in this proceeding on behalf of SWEEP/NRDC?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Southwest Gas, specifically the rebuttal testimony of witnesses Gieseking and Scott, and to the direct testimony of Commission Staff and RUCO. In my surrebuttal testimony I support the increased Demand Side Management (DSM) programs and funding proposed by Southwest Gas plus the two DSM modifications proposed by SWEEP/NRDC, discuss related DSM issues including collaborative review and Commission approval, discuss the financial disincentive to natural gas utility support of energy efficiency, oppose higher fixed charges for Southwest Gas customers, and support the one-tier rate structure proposed by RUCO.

Increased DSM Programs and Funding for Southwest Gas Customers

Q. Do SWEEP/NRDC and the other parties support increased DSM programs and funding for Southwest Gas customers?

A. Yes. With the exception of the bill assistance element of the LIEC program (which I will address below), none of the parties opposed the increased DSM programs and funding proposed by Southwest Gas, and Staff and RUCO supported the increased DSM programs and funding explicitly.[1] SWEEP/NRDC support the two existing and

[1] Direct testimony of Steve Irvine (Staff) p. 10, lines 3-5; p. 12, lines 3-6; and p. 13, line 5 (with the exception of the $50,000 bill assistance element of the LIEC program). Direct testimony of Marylee Diaz Cortez (RUCO) p. 24, lines 13-20 and p. 25, lines 2-7.

seven additional natural gas DSM programs, and in my direct testimony I proposed that DSM program funding increase from $4.385 million proposed by Southwest Gas to $5.135 million, to ensure that at least $1 million is available to support the residential new construction program (ENERGY STAR Home Certification) throughout the Southwest Gas service territory.

In addition, I proposed a positive performance incentive that Southwest Gas would earn if it implements effective DSM programs that meet program goals, resulting in a maximum performance incentive of $513,500 in 2006, based on 10% of 2006 DSM program funding of $5.135 million. Total DSM funding would be $5.6485 million including the maximum performance incentive amount.

Q. Please summarize the Preliminary DSM Plan that SWEEP/NRDC recommend for Commission review and approval at this time, subsequent to your review of Southwest Gas rebuttal testimony and the direct testimony of other parties.

A. Exhibit JS-2 (herein) summarizes the Preliminary DSM Plan that SWEEP/NRDC recommend at this time, which is a table representation of the DSM programs and funding levels I recommended in my direct testimony. SWEEP/NRDC agree that Southwest Gas should file a Final DSM Plan with program descriptions, budgets, and cost-effectiveness analysis for Commission review and approval within 120 days of the Commission's order in the Southwest Gas rate case, as Staff, RUCO, and Southwest Gas have recommended. However, SWEEP/NRDC will continue to encourage Southwest Gas to file the Final DSM Plan earlier if possible, so that DSM programs are approved by the Commission and available to assist customers as soon as possible.

Q. Does Southwest Gas support the Preliminary DSM Plan including the modifications proposed by SWEEP/NRDC?

A, Yes. In its rebuttal testimony, Southwest Gas requested that the Commission approve all of the DSM programs and funding proposed by Southwest Gas as well as the two modifications proposed by SWEEP/NRDC (i.e., increased funding for ENERGY STAR Home Certification and the positive performance incentive).[2]

SWEEP/NRDC urge Commission approval of the Preliminary DSM Plan, as a preliminary list of DSM programs and budgets, in the Commission order in this rate case. The proposed DSM programs, upon approval of the Final DSM Plan by the Commission, will provide significant and cost-effective benefits for Southwest Gas customers.

[2] Rebuttal Testimony of Vivian Scott. p. 5, lines 10-17.

Q. What is your response to Staff's exception to $50,000 of DSM funding for the bill assistance element of the LIEC program?[3]

A. SWEEP/NRDC support up to $50,000 in DSM funding for the bill assistance element of the LIEC program since it is a relatively low level of DSM funding focused on emergency situations of low income customers, and given the additional information provided in Southwest Gas rebuttal testimony.[4] If the $50,000 is not spent on bill assistance emergencies in a given year, it should be allocated to weatherization. SWEEP/NRDC suggest that the funding remain in the Preliminary DSM Plan budget at this time, and that any proposed revisions to the scope and budget of the LIEC program, including the bill assistance element, be reviewed by the collaborative DSM working group prior to Southwest Gas submitting a Final DSM Plan.

Q. What is your response to RUCO's DSM program development and approval process, including the collaborative DSM working group?[5]

A. SWEEP/NRDC support RUCO's recommended process and agree that Southwest Gas should implement and maintain a collaborative DSM working group, as stated in my direct testimony. I respectfully suggest two additions to RUCO's process (both of which were included in my direct testimony): add to the end of the last task of the collaborative so that it reads "...and review DSM program performance including program evaluations and reports;" and add AECC, the Arizona State Energy Office, and NRDC to the list of organizations to be invited to participate in the collaborative DSM working group.

Q. Should the DSM programs be approved by the Commission regardless of the outcome of the CMT and customer rate design issues, even though Southwest Gas states that the increased energy efficiency programs and the CMT were proposed together?[6]

A. Yes. While SWEEP/NRDC are sympathetic to the financial issues Southwest Gas has raised, including the declining average consumption per residential customer and the impact of additional energy savings on Southwest Gas (which I discuss below), and while SWEEP/NRDC support the joint statement of AGA and NRDC, I recommend that the DSM programs and funding be approved by the Commission in any event, and not be linked to the outcome of the CMT and customer rate design issues, because of the significant cost-effective benefits to customers including the assistance to customers in mitigating future increases in natural gas prices.

[3] Direct testimony of Steve Irvine, p. 12, beginning at line 10.
[4] Rebuttal testimony of Vivian Scott, p. 3, beginning at line 18.
[5] Direct testimony of Marylee Diaz Cortez, p. 26, beginning at line 5.
[6] Rebuttal testimony of Vivian Scott, p. 7, beginning at line 24; Rebuttal testimony of Ed Gieseking, p. 22, beginning at line 5, and p. 26, beginning at line 25.

Financial Disincentive to Natural Gas Utility Support of Energy Efficiency

Q. Did anything you read in Southwest Gas rebuttal testimony or in the direct testimony of other parties change the fundamental position of SWEEP/NRDC regarding the financial disincentive to Southwest Gas support of energy efficiency and the CMT proposed by Southwest Gas?

A. No. SWEEP/NRDC continue to state that traditional utility regulation, which links the utility's financial health to the volume of natural gas sold, results in a financial disincentive to invest in energy efficiency and other demand-side resources that reduce natural gas sales. SWEEP/NRDC also continue to support the joint statement of AGA and NRDC. SWEEP/NRDC clarify that this financial disincentive is not limited to support for DSM programs; it also could impede potentially crucial utility support for energy-efficiency standards, building energy codes, and other policies that serve societal interests and reduce energy use without requiring any direct utility or utility ratepayer investment.

From my reading of the rebuttal and direct testimony, there does not appear to be disagreement that a financial disincentive exists. However, there appears to be disagreement about the specific causes of the decline in average consumption per residential customer, and there is disagreement regarding which (if any) mechanism(s) to implement to address the financial disincentive.

SWEEP/NRDC strongly recommend that the financial disincentive to natural gas utility support of energy efficiency be addressed in Arizona in a timely manner. We believe this will be necessary if Arizona wants to fully tap the potential for its lowest cost natural gas resource – cost-effective energy efficiency improvements.

SWEEP/NRDC continue to believe that the gas utility financial disincentive issue and a full analysis of the pros and cons of mechanisms for removing the financial disincentive, including but not limited to the CMT, should be reviewed and evaluated prior to Commission adoption of a specific mechanism. This issue would benefit from a broader and more in-depth discussion, in this proceeding or in another forum.

If not addressed fully in this proceeding, SWEEP/NRDC recommend that the issue of the financial disincentive and potential mechanisms to address it be discussed in the DSM policy process, either through additional comments on the proposed DSM policies or through additional DSM policy workshops. Proposed policies or mechanisms resulting from the DSM policy process should then be submitted to the Commission. SWEEP/NRDC recommend that any such workshop commence within 60 days of the Commission order in this case, with a workshop report filed with the Commission no later than 180 days of the order.

Customer Rate Design: Fixed Charges and Flat or One-Tier Rate

Q. Should the Commission approve higher fixed charges for Southwest Gas, as proposed by Southwest Gas (as an alternative to the CMT) and by other parties?

A. No. SWEEP/NRDC oppose higher fixed charges for natural gas customers because higher fixed charges would mute and reduce the price signal customers would receive when they reduce energy use and become more energy efficient, and therefore would reduce the power they have over their own energy bills.

Q. Does the joint statement of AGA and NRDC support higher fixed charges in customer rate design, as Southwest Gas and Staff infer?[7]

A. No. The joint statement of AGA and NRDC in no way supports increases in fixed customer charges as a means to eliminate financial disincentives for promoting conservation and energy efficiency. The AGA/NRDC joint statement is explicit in stating that the "utility rate proposals" referred to by Southwest Gas and Staff that NRDC and AGA support are those that "use modest automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales."

Q. What is your response to the flat or one-tier rate structure proposed by RUCO?[8]

A. SWEEP/NRDC support the concept of a flat or one-tier rate structure proposed by RUCO, and do not support the continuation of a two-tiered declining rate structure. A one-tier rate structure would provide greater encouragement for customers to reduce their natural gas consumption through increased energy efficiency and conservation.

Conclusion

Q. Please provide an overall conclusion for your surrebuttal testimony.

A. SWEEP/NRDC support the DSM programs proposed by Southwest Gas along with the two SWEEP/NRDC modifications. SWEEP/NRDC urge Commission approval of the Preliminary DSM Plan in this rate case.

SWEEP/NRDC urge the Commission to implement programs, policies, and mechanisms that *encourage* cost-effective energy efficiency, not discourage it, for customers and for natural gas utilities. SWEEP/NRDC continue to recommend that

[7] Rebuttal testimony of Ed Gieseking, p. 20, beginning at line 2. Direct testimony of William Musgrove (Staff), p. 14, beginning at line 5.
[8] Direct testimony of Marylee Diaz Cortez, p. 35, lines 3-18.

the financial disincentive to natural gas utility support of energy efficiency be addressed in Arizona in a timely manner. Increasing natural gas energy efficiency will provide significant and cost-effective benefits for Southwest Gas customers, the natural gas and electric utility systems, the economy, and the environment.

Q. Does that conclude your surrebuttal testimony?

A. Yes.

Preliminary DSM Plan for Southwest Gas
SWEEP/NRDC
September 13, 2005

RESIDENTIAL	
Low Income Energy Conservation	$ 500,000
ENERGY STAR Home Certification	1,000,000
Multi-Family New Construction	1,200,000
Residential Energy Conservation	200,000
ENERGY STAR Appliances	800,000
COMMERCIAL	
Food Service Equipment	500,000
Efficient Commercial Building Design	500,000
Technology Information Center	35,000
INDUSTRIAL	
Distributed Generation	400,000
Subtotal for DSM Programs	**$ 5,135,000**
Performance Incentive (capped at 10% of DSM program cost)	513,500
TOTAL	**$ 5,648,500**

Note: Southwest Gas should file a Final DSM Plan with program descriptions, budgets, and cost-effectiveness analysis for Commission review and approval within 120 days of the Commission's order in the Southwest Gas rate case.

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BEFORE THE ARIZONA CORPORATION COMMISSION

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-04-0876

SURREBUTTAL TESTIMONY OF DAN L. NEIDLINGER

ON BEHALF OF

THE DEPARTMENT OF DEFENSE

SEPTEMBER 13, 2005

ARIZONA CORPORATION COMMISSION
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-04-0876

Surrebuttal Testimony of Dan L. Neidlinger

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Dan L. Neidlinger. My business address is 3020 North 17th Drive, Phoenix, Arizona. I am President of Neidlinger & Associates, Ltd., a consulting firm specializing in utility rate economics.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.

A. A summary of my professional qualifications and experience is included in the attached Statement of Qualifications. In addition to the Arizona Corporation Commission ("ACC"), I have presented expert testimony before regulatory commissions and agencies in Alaska, California, Colorado, Guam, Idaho, New Mexico, Nevada, Texas, Utah, Wyoming and the Province of Alberta, Canada.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Department of Defense ("DOD"). The DOD installations in Arizona served by Southwest Gas Corporation ("Southwest" or the "Company") include Davis Monthan Air Force Base ("DM"), Luke Air Force Base ("Luke"), Yuma Marine Air Station ("Yuma") and Fort Huachuca. DM, Luke and Yuma are currently serviced by the Company under the Armed Forces tariff, Rate Schedule G-35. Fort Huachuca is currently served under a special contract but will begin taking tariffed service on October 1, 2005.

Q. WHAT IS THE COMBINED ANNUAL GAS USAGE OF THESE DOD FACILITIES?

A. These military installations are some of the Company's largest customers. Combined annual gas usage for these facilities totals 658,000 decatherms. Fort Huachuca's usage represents approximately 48% of this total.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to briefly comment on the direct and rebuttal testimonies of Company witnesses Gieseking and Congdon and the direct testimony of ACC Staff witness Gray with respect to rate design proposals that affect DOD facilities. The Company is proposing in this case to eliminate Rate Schedule G-35, the Armed Forces rate schedule, and transfer all DOD customers to the Large General Gas Service rate, Rate Schedule G-25. The Residential Utility Consumer Office ("RUCO") does not object to this consolidation. Staff, however, recommends maintaining the current Rate Schedule G-35 for DOD customers with the provision that these customers could elect to take service under Rate Schedule G-25.

Q. DID THE COMPANY EXPRESS CONCERNS ABOUT PROVIDING DOD CUSTOMERS WITH RATE OPTIONS?

A. Yes. In his rebuttal testimony, Company witness Congdon asserts that the Company could experience a short-fall in margins if DOD customers were allowed to choose to take service under either Rate Schedule G-25 or G-35. If Staff's rate proposals for Rate Schedules G-25 and G-35 are adopted in this case, it is unlikely that there would be any migration to Rate Schedule G-25 since annual gas costs to DOD customers would increase. Accordingly, the Company's concerns are unwarranted. Staff's recommended rates essentially maintain the status quo and provide no realistic rate-switching option for DOD customers.

Q. DO YOU HAVE ANY OBJECTION TO THE COMPANY'S PROPOSAL TO TRANSFER DOD CUSTOMERS TO RATE SCHEDULE G-25?

A. No. DOD customers should logically be classified with other large gas users for ratemaking purposes. Fort Huachuca has requested service under Rate Schedule G-25. The Fort understands that it must initially take service under Rate Schedule G-35 and that G-25 will not be available until the conclusion of this case.

Q. THE COMPANY IS PROPOSING TO CHANGE ITS METHOD FOR MEASURING A LARGE CUSTOMER'S PEAK DEMAND FROM A COINCIDENT PEAK METHOD (SYSTEM PEAK MONTH) TO A NONCOINCIDENT PEAK METHOD (CUSTOMER PEAK MONTH). DO YOU AGREE?

A. Partially. Staff recommends that a customer's billing demand continue to be ratcheted based on its monthly demand at the time of the Company's system peak – normally a winter month. I would support a modified noncoincident peak method whereby a customer's billing demand would be based on the highest monthly demand experienced during any winter month. Demands during the summer months of May through September would be exempt from the calculation.

Q. HAVE YOU REVIEWED THE RECOMMENDED LARGE CUSTOMER G-25 RATES PROPOSED IN THIS CASE?

A. Yes. I have reviewed and analyzed the rate recommendations for large, transportation eligible customers proposed by the Company, Staff and RUCO in this case as well as the cost of service studies prepared by the Company and Staff. The overall revenue requirements proposed by the Staff and RUCO are comparable. Should the Commission set revenue requirements at or near these levels, RUCO's proposed G-25 rates are preferable to Staff's recommended rates since they better reflect cost of service.

Q. DOES THAT CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

DAN L. NEIDLINGER

SUMMARY STATEMENT OF QUALIFICATIONS

I. General:

Mr. Neidlinger is President of Neidlinger & Associates, Ltd., a Phoenix consulting firm specializing in utility rate economics and financial management. During his consulting career, he has managed and performed numerous assignments related to utility ratemaking and energy management.

II. Education:

Mr. Neidlinger was graduated from Purdue University with a Bachelor of Science degree in Electrical Engineering. He also holds a Master of Science degree in Industrial Management from Purdue's Krannert Graduate School of Management. He is a licensed Certified Public Accountant in Arizona and Ohio.

III. Consulting Experience:

Mr. Neidlinger has presented expert testimony on financial, accounting, cost of service and rate design issues in regulatory proceedings throughout the western United States involving companies from every segment of the utility industry. Testimony presented to these regulatory bodies has been on behalf of commission staffs, applicant utilities, industrial intervenors and consumer agencies. He has also testified in a number of civil litigation matters involving utility ratemaking and once served as a Special Master to a Nevada court in a lawsuit involving a Nevada public utility.

Mr. Neidlinger has performed feasibility studies related to energy management including cogeneration, self-generation, peak shaving and load-shifting analyses for clients with large electric loads. In addition, he has consulted with U.S. Army installations on privatization of utility systems and assisted these and other consumer clients in contract negotiations with utility providers of electric, gas and wastewater service.

Mr. Neidlinger has extensive experience in the costing and pricing of utility services. During his consulting career, he has been responsible for the design and implementation of utility rates for numerous electric, gas, water and wastewater utility clients ranging in size from 50 to 25,000 customers.

IV. Professional Affiliations:

Professional affiliations include the American Institute of Certified Public Accountants.